COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:)
)
The Preparation of the 2005) Docket No. 04-IEP-1
Integrated Energy Policy)
Report (2005 Energy Report))
)

CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

FIRST FLOOR, HEARING ROOM A

SACRAMENTO, CALIFORNIA

THURSDAY, JULY 7, 2005

9:30 A.M.

Reported by:
Sean Willard
Contract No. 150-04-002

COMMISSIONERS PRESENT

John L. Geesman, Presiding Member

James D. Boyd, Associate Member

Jackalyne Pfannenstiel

ADVISORS

Melissa Jones, Advisor

Michael Smith, Advisor

STAFF PRESENT

Kevin Kennedy

Karen Griffin

ALSO PRESENT

Tom Flynn, Deputy Director
CPUC

Maryam Ebke, Acting Director Strategic Planning
CPUC

James Hendry, Strategic Planning
CPUC

Steve Greenleaf, Director of Regulatory Policy
CAISO

Kevin Woodruff, Consultant
TURN

Robert Kinosian, Policy Advisor
ORA

Wayne Sakarias, Director, Legislative Analysis
SDG&E

ALSO PRESENT (Continued)

Stuart Hemphill, Director of Resource
Planning and Strategy
SCE

Hal LaFlash, Director Gas and Electric Supply
PG & E

Katie Kaplan, Manager for State Policy
IEP

Bob Anderson, Director Commodity Operations
APS Energy Services

Fred Buckman, Chairman of the Board
Trans-Elect

Jesus Arredondo, Director of Regulatory and
Governmental Affairs-Western Region
WPTF

I N D E X

I N D E X (Continued)

P R O C E E D I N G S

PRESIDING MEMBER GEESMAN: This is Day 42 of the workshops for the Energy Commission's 2005 Integrated Energy Policy Report. I'm John Geesman, the Presiding Member of the Integrated Energy Policy Report Committee.

To my left Commissioner Jim Boyd, the Associate Member. To his left, Mike Smith, his staff advisor. To Mike's left, Commissioner Jackalyne Pfannenstiel. To my right, Melissa Jones, my staff advisor.

We are using today to try to frame some big picture questions, if you will, that hopefully will get input on from the various stakeholders as to questions that ought to be addressed in our report which will be released later this fall.

I recognize that the relevance of any particular question or the perspective needed to fully address it is really a function of when you pose the question, and issues that may appear important today may be less important 90 days from now.

At the same time, our staff and consultants have attempted to frame issues that we think will be of enduring priority over the course of this cycle. We certainly welcome the input of all of the participants that we have been able to attract to our agenda today and will certainly invite additional public comments as well.

I would ask you to please let us know if you think that there are other issues that we should direct more focus on or if you think we are looking at something in a way that isn't perhaps as illuminating as you believe that it should be.

Commissioner Boyd?

COMMISSIONER BOYD: Thank you. Just want to underscore what Commissioner Geesman said about the importance of this subject to the Integrated Energy Policy Report which we hope is a product that is valuable to all of us who work in the energy arena, most particularly in the electricity area, so I look forward to a very fruitful discussion today, and I think we should begin.

PRESIDING MEMBER GEESMAN: Kevin, do you want to kick things off?

MR. KENNEDY: Yes, thank you, Commissioner. My name is Kevin Kennedy, and I am the program manager for staff for the 2005 Integrated Energy Policy Report. I want to welcome everyone who is here today and listening on the web or on the phone to this workshop.

We do hope to have a very productive set of discussions with the different panel, discussions through the course of the day.

I just want to give first some quick housekeeping items. I think most of you who are here today actually are pretty familiar with this set up and all, but in case there are any folks who are not, restrooms are outside, down the hall to the left. I have to ask you to be sure not to go out the door to the outside through that side. I'm sure somewhere in the course of today we will hear the alarm go off when someone does actually go through that door.

If you are looking for coffee or snacks, there's a snack bar upstairs sort of just upstairs, pretty much straight ahead.

I would also like to ask folks as we get to the public comment during the course of the day that this is being recorded so I would like to ask folks to identify yourself, what organization you are with. If at all possible if you can hand off a business card to the court reporter as you are going up to the mike or going back because it is being recorded, we do ask that anyone who is making comments to come up to the microphones.

I just want to give a very quick overview of what we are doing today. First we have a couple of panels this morning. Then we will be taking one round of general public comment. In order to make sure that we accommodate anyone who can't stick around for the afternoon session, if you do need to speak this morning, please there are blue cards outside in the entry way. If you could fill out a blue card, we will get them up to the dias and make sure that you can have your comments in this morning.

Then we will take a lunch break and then we have a couple more panels in the afternoon and then a final round of public comment.

This is also one of a series of workshops, particularly on the electricity and natural gas issues. As Commissioner Geesman pointed out, this is I think No. 42 in the overall course of things from when we started with the scoping hearing last fall.

Last week we had hearings on the IOU resource plans that had been filed with the Energy Commission and on the demand forecast both staffs and the ones that have been filed by the various load serving entities, as well as a workshop on looking at strategic value analysis for integrating renewables.

Next week we have a workshop on energy efficiency. I would like to point out that will be up at Cal EPA and has a 10:00 starting time. Next Thursday, the 14th, we have a workshop on natural gas forecast and policy options.

At the end of July, we have additional workshops on implementing the loading order and taking a look at the statewide and western regional resources and also a workshop on transmission.

We come back to natural gas issues in early August. There are a number of other workshops that may be of interest over the course of this period including a Climate Change Advisory Committee meeting on Monday and a workshop on climate change next week on Tuesday.

In August, we will be taking something of a look at nuclear issues and clean coal issues in workshops in mid August, so I encourage folks to take a look at the Energy Commission, the IEPR portion of the website for a complete listing of the upcoming workshops.

I do want to post the call-in number for folks who are listening in on the webcast if you decide that you want to make comments. The number is 888-942-8132. The pass code is workshop, and the call leader is Peggy Faugust.

I'll leave this slide up so that folks who are looking at the webcast can refer back to it if you want to call in. Anybody who is listening in on the call-in number, just a quick reminder that the phone lines are open to the rooms, so any background noise does get amplified, so we ask you to keep your phone on mute if at all possible. I do encourage the use of the webcast for listening in if you are not planning to make any comments.

With that, I want to turn it over to Karen Griffin who is going to be doing the master of ceremonies job for the day, sort of bringing the panels up and back as we go through the day. Thank you.

MS. GRIFFIN: Thank you, Kevin. I understand that the price for actually getting one set of comments in on time goes to Southern California Edison. For the rest of you, written comments are due by July 18. That date is in the notice.

We are starting off with a panel of state entities, and this consists of the PUC, the ISO, and ORA. Robert Kinosian is still on his way. Our PUC panelists starting off with James Hendry from Strategic Planning, I think to be followed by Tom Flynn who is the Deputy Director now of the Office of Legislative Affairs, and Maryam Ebke, who is the Acting Director of the Division of Strategic Policy, will then be followed by Steve Greenleaf who is the Director of Regulatory Policy for the ISO. Batting clean up will be Robert Kinosian, Policy Advisor, for the Office of Rate Payer Advocates.

We have asked the panelists to make their presentations then to have Commissioner comment or questions on that and then invite both the panelists and members of the audience to talk about the issues that people have raised. Members of the audience, you need to walk up to a mike and talk so that your voice will go out over the web, and our transcriber will get the information. If you do talk, please give the transcriber a business card so that your name and organization can be spelled correctly.

With that, I'll turn it over to James.

MR. HENDRY: Thank you for the opportunity to address the Commission today. President Peevy sends his reqrets that he could not join you at this hearing. He is currently in Southern California at the ceremony dedicating the energizing of the Mission Regal Mine.

As a result of the Energy Action Plan, I think the PUC views itself as much a partner in this proceeding as a participant. We look forward to the comments of the other parties in helping us and you both frame the debate that California has to face.

The results of your process should provide the PUC with the recommendations and establish an evidentiary record that will feed into our proceedings. Therefore, we look forward to some of the comments that parties will be making.

The CEC should be commended for the issues that it has raised today. It has clearly addressed all of the big issues. We have on-going proceedings that are trying to seek answers to many of the very same questions.

Given the breadth of topics to be covered, clearly will be a stretch to cover all of these in the 15 minutes provided. We will try and hit the highlights and try then, if you have follow up questions, please feel free to ask them.

I will be planning to focus on the issues of electric utility and supply and your liability. Tom Flynn will then address transmission issues and Maryam Ebke will address natural gas issues.

With regard to electric issues and liability, the Commission developed its 15 to 17 percent reserve level as a result of evidentiary hearings in which the CEC and the ISO participated. Testimony in this proceeding confirmed that it was consistent with a one in ten year reliability standard which was the current goal.

The reserve level is consistent with what other ISO's have adopted. It is consistent with what the California ISO sets for municipal utilities becoming metered sub systems under its rules.

At the request of the administration, the Commissioner accelerated the implementation of these goals from 2008 to 2006.

Given the current supply situation, particularly in Southern California, our short-term focus should clearly be on achieving these reserve levels by the 2006 deadline and applying them to all load-serving entities.

The Commission has just issued its Workshop Report on how to implement these resource adequacy guidelines, and we plan to issue decisions on this later this year.

We share the concern expressed in the workshop notice that any resource adequacy framework should address how to treat soft resources properly such as energy efficiency, demand response, and renewables.

Longer term, the Commission could reexamine the appropriate level of the reserve margin if needed. One of the successful outcomes of the Energy Action Plan was to bring together all of the energy agencies to develop a common forecasting methodology. The benefit of this is now we are able to look at not only the effect of hot weather in system operations, but also other factors such as plant outages of low hydro, and thus we can begin to sort of develop more refined estimates of what is the probability of hot weather year occurring with a low hydro year occurring with excessive plant outages to help define various probabilities and develop scenarios that we can then better plan with.

There is also an interaction longer term between the reserve margin levels and dynamic and real time pricing. Successfully implemented, real time dynamic pricing could help reduce the level of reserve margins needed to maintain a reliable system.

Turning to the issue of resource options, once California has made the decision, what is the appropriate level of reliability. We then have to decide the issue of how do you want to meet these issues and what are the major policy goals to address these.

The workshop notice clearly provides a broad menu of options of potential resources upon which California could rely. It is here I think it is important to rmemeber the phrase "integrated" in the CPUC's Integrated Energy Policy Report.

Each of the resource options offers different characteristics as to type of resource, base load, load following, peaking, costs, environmental benefits, reliability, deliverability.

The challenge for California is finding the right mix of these resources and that best meets the goals that we both agree on, reliable, environmentally sensitive service at reasonable rates.

The concept of integrated energy planning that you are engaged in is very similar to the concept of least cost/best fit methodology that the Commission is using in its procurement practice.

Integrated planning should fit well into the least cost/best fit methodology adopted by the PUC to evaluate new resources.

It is also important to look at when you are looking at the range of diversity, costs, environmental benefits, to take into account the range of potential outcomes. For this reason, we have requested the utilities provide their best thinking in their long term plans, and that these plans when we examine them will be examined in our procurement proceeding.

It is also important that the utilities

provide a range of outcomes, not just essential estimate so that we have a range of scenarios so that we can decide then based on outcomes or a range of outcomes and likely probabilities of them occurring.

Diversity is not only a matter of resources, it is also a matter of outcomes. The CPUC has made this request to the Energy Commission that in your Integrated Energy Policy Report that you begin to help us address the range of possible variations and outcomes that could come from various resource options.

Regarding the menu of options, I would like to briefly run through them and offer comments in a way of the Commission's current thinking is. With regard to new power plants, the over hang of 8,000 MWs of permitted yet unbuilt construction is clearly the result of two factors. One, I think there is some what Alan Greenspan, the Chairman of the Federal Reserve Bank would call a "rational exuberance" as developers rush to build power plants based on expectations of high energy prices.

Second, there is clearly a back log as a result of the financial melt down of California utilities that prevented them from making long-term commitments.

Having restored the utilities back to their financial stability, the Commission is doing as much as it can to move as many plants as possible from the permitted side of the ledger over to the operating side of the ledger.

Mountain View, Palomar, Otay Mesa are all projects the Commission has approved. Soon we will be considering PG & E's request to repower and finish the Contra Costa 8 plant that it received from Mirant as part of its settlement regarding market manipulation issues arising from the energy crisis.

We also have the potential for several thousand MWs of new capacity coming from RFO's issued by PG & E and Edison.

Longer term, some over hang of permitted but unbuilt capacity should be viewed as a sign that California has a viable energy market. We should view permitted generation as an inventory, not as a wasted resource.

Many developers are willing to invest the significant time and money to permit new power plants in order to have a place at the table and be able to build when market conditions warrant.

What is important for these developers are two things. First, that they know clearly defined rules as to what the environmental and permitting and siting conditions are going to be, and this is a role that the Energy Commission has been very successful at.

Second, they need to know that the utilities procurement rules will be open, clear, and transparent, something the PUC is implementing in its policies.

At the other end of the spectrum from new power plants, we have the existing largely divested power plants. The Energy Commission is asking if current policies are precluding the repowering of these plants.

The Commission has taken steps to insure that these plants remain available. They provide important power to California to meet local reliability needs. Many of them also provide very important sort of load following and peaking capabilities. Thus, they meet the least cost/best fit criteria of providing a range of resources to meet the various and shifting load patterns of the state.

Second, retirement prevention may be the best short term policy. Keeping these plants available under short-term contracts essentially is providing California with an option that will allow us to repower these plants in the future and keep them available for electric generation.

With regard to qualifying facilities, the Commission shares the concerns of the CEC of the importance of these resources, and as the proceedings develop a long-term QF policy. In the interim, the Commission has directed the utilities to offer one year contract extensions to QF's who have either expired contracts or soon to be expiring contracts.

Our proceeding in this issue raises many of the same issues of least cost/best fit analysis in integrated policy planning. For example, what are the contract terms that these contracts should be renewed under. Should there be changes of flexibility in the delivery options? What is the price paid for this power and the length of any new contracts?

With regard to coal by wire, the proposed Energy Action Plan 2 proposes that electricity supply serving California from any source are consistent with the governor's Climate Change Policy.

At this time, very little of the power used by California is generated from coal. Coal can provide diversity benefits, but clearly has environmental consequences. Clearly there is a trade off between making coal cleaner, including potentially dealing with the issue of carbon emissions and carbon sequestration and its cost effectiveness.

As noted in the CEC's question, there is also question of the potential technology risk of the time and effort needed to develop the technologies that will provide us with clean coal.

We have supportive efforts to develop this technology and improve the environmental profile of coal, and we look forward to the workshops that you've announced in August that will further explore this issue.

Finally, under renewables energy efficiency, although we discussed them last, clearly they are first in the Commission's thinking. They are the preferred resources at the top of the EAP loading order. Over the last year, the Commission has adopted long range energy efficiency goals, and the utilities have signed contracts for between 900 to 1,200 MWs of new renewable resources.

Your panel question asks about how we can incorporate them into resource planning. I think with energy efficiency, we have been very successful in incorporating them into energy resource planning as well as with renewables.

There are other concerns with renewables that the Commission and the CEC are both addressing which deal with one, trying to make sure that renewable energy can be delivered, so we are looking at issues such as Tehachapi transmission area and upgrades to transmission in that area, as well as the effect that some renewable resources, primarily wind, which is more of an intermittent resource, has on system operation. These are issues which we look forward to studying further.

Finally, I would like to talk briefly about utility contracting procurement. As shown above, the utilities procurement efforts have resulted in new power plants, both traditional and renewable coming on line.

The Commission has directed the

utilities to achieve a mix of long, mid, and short term contracts consisting with traditional portfolio theory, and to give California the flexibility which could result to change market conditions.

The appropriate mix of contract types is one of the things the Commission will look at in its procurement proceeding. The Commission also has an on-going proceeding to look at procurement incentives and how they can be used to promote new capacity being developed.

We are also looking into capacity markets, and in February of this year, President Peevey directed the staff to report back on how to implement a capacity market, issues that needed to be addressed, and how markets such as that could be developed.

Although procurement activities have resulted in new construction, the utilities have expressed concerns about signing longer term contracts without further policy development by the PUC and Energy Commission and concerns about the future market structure.

With that, I would like to have Tom talk about transmission issues and then Maryam talk about natural gas issues.

MR. FLYNN: Good morning, Commissioners. In looking at the transmission questions in the workshop notice, I would definitely say we share the focus of many of those transmission related questions and concerns.

You pose the question of do we need more transmission, do we need a more robust transmission system. There is definitely recognition of the need for the timely addition of new transmission infrastructure in California.

Quite simply, we've got to accommodate load growth, we have a mandate connecting renewable generation to the grid, we need to interconnect other new generation, and we need to look for ways to reduce local market power generating units such as reducing the reliance on must-run generation.

We've got to explore and consider opportunities for importing power from the most economic sources over long distances, and we need to consider a transmission's ability to provide flexibility in our choice of power sources, an easier substitution in the case of failure in the system.

As a general matter at the present time, more transmission is probably better, but that statement by itself is not policy. It is definitely a balancing act. We are all familiar with some of the negatives associated with transmission. It is ascetically undesirable, it has negative environmental consequences, it is hard to site. The benefits are not always enjoyed by those whose environment is affected.

We do have a loading order that we've all embraced and try to put things first, forward energy efficiency as an example first in the loading order. There is a lot of support for that. I know in the legislature, I am familiar with a bill over there that Senator Kehoe has to codify actually that portion of the loading order. The PUC supports that bill.

Despite the challenges of siting new transmission, I'd like to note that fortunately that the PUC has of late approved some important transmission projects. As Jim Hendry was mentioning, San Diego's Mission Miguel Project, a portion of that was accelerated, and there is an event relative to the energization of that accelerated portion. The PUC worked with San

Diego Gas and Electric to move up the date of that accelerated portion to be of use for this summer.

There's Edison's Viejo Project and PG & E's Jefferson Martin Project. The latter project is one that definitely has some challenges associated with it that we had to work through.

The transmission results and recommendations of the IEPR process will definitely provide some very valuable input into the PUC's long term procurement process. It is something that we are looking forward to receiving in terms of that input. We know the Commission is putting a lot of effort into that, and I think it will be extremely helpful. It will help inform the supply plans that are ultimately submitted by the IOU's in our long term procurement process in the 2006 cycle.

In terms of long term procurement in transmission, the PUC is responsible for reviewing and approving the long term procurement plans of IOU's. Those plans will identify transmission upgrades and additions that are necessary to support those supply plans or those resource plans. That process needs to be very well coordinated with the ISO's long term group planning process and the CEC's IEPR process.

In the 2004 cycle, we provided feedback to the utilities that we think there should be a stronger linkage going back to one of your questions, there should be a stronger linkage between the process of identifying supply options and transmission options and have directed them to strengthen that linkage in the next cycle of our procurement process.

Coming out of that, we have some CPCN applications that are currently before us. We have Otay 230 KV Project associated with the generation project. We have Deevers Palo Verde No. 2 and some Tehachapi wind resource related transmission. Antelope Party 500 KV, known as Antelope 1, and then the project known as Antelope 2, the Antelope Tehachapi Vincent 500 KV, both of those are before us.

We also are considering some permits to construct, a slightly lesser process than a CPCN for projects less than 200 KV, there is a Silver Gate 138 KV underground line and substation and the Lakeville Sonomoa 115 KV line.

In addition, we also have other projects that are under study, the Antelope Mesa 500 KV reconductor and rebuild, the second Antelope Vincent 500 KV line, the collector system for the Tehachapi wind farm, the Tehachapi Greg Tesla 500 KV line, Tehachapi Midway Tesla 500 KV line, the Salt and CG thermal 330 KV line to enable that tremendous renewable resource area to better connect to the grid and the Delta 230 KV substation.

MS. EBKE: Good morning, I know we have already gone over our 15 minutes, so I will have very brief remarks on natural gas trying to respond to questions.

As I am sure you are aware, PUC is working collaboratively with the Energy Commission and other state agency on natural gas issues, both in natural gas and liquified natural gas LNG working groups.

We have jointly sponsored many workshops. I know some of you have attended those workshops to address natural gas issues and explore ways to insure reliable supply of natural gas exists for California consumers.

The last time PUC made an overall evaluation of the adequacy of California's natural gas infrastructure was at the end of 2001. At that time, the PUC found that the state's natural gas transportation and storage system was adequate for the period of 2002 to 2006 to provide seasonally reliable amounts of competitively priced natural gas to residential, commercial, industrial, and electric generation customers.

There have been no curtailments of any California natural gas consumers since that time, and none are expected by the end of 2006.

In order to insure that adequate natural gas infrastructure for electric supply exists, the state needs to establish policies and regulatory structures that would do the following: a certain amount of slack capacity on interstate and intrastate natural gas transmission lines, sufficient natural gas storage capacity for utility customers who want to use that service, we need to insure that there is non-discriminatory open access to utility systems for new sources of supply such as LNG, and diverse access to natural gas supply areas, particularly to low cost supplies must be available.

The PUC is currently considering these issues in various proceedings, especially in rule making R0401025. In that proceeding, the PUC directed the utilities to submit tariffs and also set forth a policy for non-discriminatory open access to utility system for new sources of supply.

In order to more fully understand the adequacy of the California natural gas infrastructure and the impacts of current procurement practices, the PUC's energy division is gathering information from the electric utilities and will be issuing a report on September 15, 2005 addressing the natural gas requirements of the state's regulated electric utilities and whether adequate infrastructure will be available in the future to serve those requirements.

In addition, the PUC just received testimony from SoCal Gas, SDG & E, and PG & E on June 14 regarding the appropriate amount of slack capacity on their system under a variety of different scenarios, adequacy of storage, and recommended policy including deliverability standards on when and under what conditions utility infrastructure enhancements should be built. Other parties will have an opportunity to file testimony on those issues.

Finally in another SoCal Gas SDG & E application 0412004, the PUC is considering proposals for firm access rights under SoCal Gas and SDG & E Systems. I should note that a system of firm tradeable transmission and storage rights already exist on PG & E's system.

After the Commission reviews the evidence and briefs and comments of parties, it can determine whether the electric utilities current efforts will insure that there will be sufficient natural gas infrastructure to support their electricity supply.

If the electric utilities have not done so, it may be appropriate to require electric utilities to obtain firm natural gas transmission and storage rights so that their natural gas requirements can be met on a highly reliable basis.

The Commission, however, has no jurisdiction over municipalities which provide their own electric supply, therefore, the Commission has no way of knowing whether the municipalities will have sufficient natural gas infrastructure to meet their electrical needs.

With that, we will be happy to answer

any questions you might have.

PRESIDING MEMBER GEESMAN: Maryam, Tom, and Jim I want to thank you for being here and for the remarks that you've made and also for the close working relationship that our staff and yours have enjoyed throughout this process.

I have a couple of questions largely for Jim and Tom prompted by a couple of things that you said. First on the resource adequacy criteria, I don't know, Jim, if you were at the last Energy Action Planning Meeting that we had, the joint commissions and cabinet secretaries, but I was very alarmed by the presentation that the Energy Commission staff made showing that even with the 15 to 17 percent planning reserve margin and a 7 percent operating reserve margin, that conditions in Southern California under hot temperature, one and ten weather year, still came down to unacceptable low levels. My recollection, and I may be wrong on the specifics, but my recollection was that projected reserve, having met the operating reserve criteria, having met the planning reserve criteria, would more likely be less than 1 percent in a one in ten.

The conclusion I draw from that, and my

question is whether you think the conclusion or the inferences is appropriate, the conclusion I draw from that is that we have not adequately interconnected our generating facilities with load and that the way in which to make those reserve criteria better suit adverse weather conditions would be to improve our transmission intercom activity, and that the real drain on our system in that table that I think all of the staff now have agreed in terms of the format, the real drain there comes from the ISO assumptions about transmission limitations.

MR. HENDRY: I think you've raised a very good point in what is in the Resource Adequacy Report is the question of deliverability, so it is 15 to 17 percent, and it has moved beyond sort of, you know, a statewide look or even a utility look, and will likely when finally implemented be down to some sort of local deliverability area that will address then transmission constraints.

I think once we get to that level and get the resources in place, I think I agree with you that then the levels probably should be sufficient because you want to make sure that one of the criteria is making sure that resources that you count are deliverable and that the transmission capacity is there. So, I think we are in agreement on that issue in that it is more of a question from the Resource Adequacy Workshop Report how to implement that given the current resource situation whether, you know, the speed with which we can phase that in.

PRESIDING MEMBER GEESMAN: Because I don't think it is either feasible or desirable from a policy standpoint to head in the other direction, which is to suggest that our planning reserves need to be adjusted upward to the mid 20's or higher in order to provide for that adverse weather scenario. I haven't heard anyone suggesting that we can realistically move that planning reserve target up above the fairly aggressive 15 to 17 percent that we have been observing for the last couple of years.

Let me ask you as well, your comments about the benefits about the existing plants. It causes me a little concern in the context of the study we did last year as to the attributes of the so-called aging plants. I think that you accurately capsulized the various benefits. I think there are some real detriments though as well, and I think they relate to that 8,500 MWs of permits that have not yet proceeded to construction.

When we looked at the existing plants last year, we saw that on average they were operating 21 to 22 percent of the time. The investment banker in me says nobody would make any money at 21 or 22 percent operating factor, and certainly no developer of a new plant is likely to find that operating profile an attractive one.

These plants are, I think, anticipated or hoped to operate when they are new in excess of 65 or 70 percent of the time, and I think the financings are based on those types of assumptions, which is one of the reasons why we seemed to have moved to a utility procurement model, and most of the country is determined that the merchant model is dead.

Doesn't that suggest that we've got too many old plants around if we are going to encourage procurement that results in the construction of new plants, aren't we going to have to replace the old plants? Don't they constitute an over hang that makes investment in new plants unattractive?

MR. HENDRY: That is a very complex question, and I think that it is one that would benefit from extensive analysis. I think, you know, one concern is you do have the least cost/best fit analysis, and you do have a load profile that goes up and down, and there is a need for load following plants.

If you want to also have extra plants available to deal with planning and operation reserve margins, then it is quite likely that under any system, you are going to end up with a fair number of plants that are going to be load following plants or only going to run 20 to 30 percent of the time --

PRESIDING MEMBER GEESMAN: Or less.

MR. HENDRY: -- or less, and clearly the financial market would rather build base load plants, and you can build peaker plants as we did during the energy crisis, and maybe what we need to look at is sort of a life cycle of plants that many of these plants, you know, started as base load plants, and as they got older now and become less efficient, they have moved to basically being load following plants. To the extent you need load following plants, and the market doesn't seem to build them, then this may be the relative candidate pool from which we end up getting most of our load following capabilities.

It does not rule out that some of these plants over time may be beneficial and cost effective to repowering and become base loaded plants, but I think, you know, unless there is a need that these plants will run as base loaded plants, I am not sure it makes sense to repower them and considering have them run 20 percent of the time to the extent that they are older and are running 20 percent of the time currently. That may be the way to keep them going.

Because of the load following benefits that they provide, you also have to look at I guess for at least these existing plants is these plants are older or depreciated, they were purchased when the utilities sold off the power plants to them. They were sold off, I think the average book value is about $150 a KW, which is significantly below the 700 KW or so you would need for a new power plant.

Even when you add in pollution retrofits, on-going maintenance, you know, there is an economic calculation that should be made that may be at 22 percent. How profitable or unprofitable they are, and then longer term when you start phasing in resource adequacy clearly these plants may be the sort of the prime candidates that you looking more for longer term capacity contracts for them to make their return rather than sales under the energy market. So, is the resource adequacy a longer term capacity markets get phased in or even pre-resource adequacy, just the existing procurement activities that the utilities have engaged in and signed these plants up to meet local reliability needs may give them a cash flow sufficient to keep them around.

PRESIDING MEMBER GEESMAN: Is that good? Are these artificial life support mechanisms, which are really the only reason those existing plants are still around, are they a disincentive to new construction, new investment?

MR. HENDRY: They may be on the margin, but there will be a need for load following plants, and somehow that does not seem to be a market that either the investment community seems willing to invest in or that may make sense from an economic perspective to build new plants to then have them run 20 percent of the time.

Ideally, I think there may be a middle ground where you have new plants come on line in advance of need and can sort of serve this load following purpose, and then as demand grows, they move to being base loaded plants, that was one of the justifications at the Mountain View plant, the assumption to come on originally to provide sort of load following benefits, and there is load growth rows would become a base load plant.

I haven't checked, I think recent forecasts may have changed that operating paradigm, but you know, I think there is an interaction there, but there are also benefits that I am not quite sure how you weigh the two, and I think that is an issue that clearly your agency and our agency need to look at, and I think we are looking at.

PRESIDING MEMBER GEESMAN: Tom, I had a couple of questions related to transmission. You ran through the lengthy laundry list of individual projects. I guess one of the concerns that I think continues to hang over this whole subject matter is those projects are all applicant driven.

Is an applicant driven process likely to result in the types of infrastructure or lines or routes best configured to meet California's future needs, especially when those needs change rapidly?

An example being the renewables area the state has jumped on so hard over just the last several years, is an applicant driven planning process ever likely to result in a good match up to the state's strategic needs?

MR. FLYNN: I guess maybe a different point of view would be instead of -- I guess I don't really view it as completely an applicant driven process. I mean quite honestly, I view the IEPR process, the PUC's procurement process, the ISO's grid planning process, the WECC processes as all having a hand in forming what ultimately is applied for in terms of permit at the relative regulatory agencies involved, whether they be muni's or IOU's in California or what have you.

The applicant step is kind of the way I look at it is one of the later steps that happens after lots of interested entities have played a role in trying to influence what ultimately is applied for. I see it as somewhat of a kind of a conglomerate of many interests.

PRESIDING MEMBER GEESMAN: Walk me through Tehachapi Segment 3 and tell me how that has worked. My perception is you told Edison to do it, they sued you in state court, they won. They came up with a good idea, a renewable trunk line. They went to FERC to get permission to do it, your Commission, my Commission both said this is a great idea FERC, help us address our infrastructure problems, authorize us to do that.

The FERC staff and others said that is too much of a delegation of power to the state commissioners, let's keep that jurisdiction here, and FERC seems to have taken that option away from us. Where do we go with Segment 3?

MR. FLYNN: I wish I had a good answer for you. I have to apologize, I am not as up on that as I wish I was.

PRESIDING MEMBER GEESMAN: Let me ask you a different question then. Jefferson Martin decision involved undergrounding some of the line to an eleven foot depth. Do you see that becoming a new standard for undergrounding? I believe in Jefferson Martin it was suggested as an EMF mitigation measure.

MR. FLYNN: I think it was in direct

response to concerns of homeowners and landowners in the area. I don't necessarily see it as precedent setting. It would certainly have pressure in that direction. There would be those that would like to see it be precedent setting, but I don't think the Commission views it that way.

PRESIDING MEMBER GEESMAN: What is the difference between three feet and eleven feet?

MR. FLYNN: Again, I think it was in response to concerns raised by some of the homeowners in the area. As I mentioned earlier, siting transmission is a challenge, and, you know, getting the support of those that are directly affected by a new transmission line is very important, and I think it is just part of the balancing process of trying to get an important line like Jefferson Martin on line.

PRESIDING MEMBER GEESMAN: Thanks very much. Commissioner Boyd?

COMMISSIONER BOYD: Thank you. First I want to thank the three of you as Commissioner Geesman did for being here, and I want to amplify what Maryam said about the cooperative work that our agency has been doing as she and I know in particular I guess on the natural gas area.

I want to just ask a question about the 8,000 MWs of permitted but not built generation we have sitting in reserve, I guess, I don't know if that is a good Chamber of Commerce reserve to have or not with regard to the business climate of California. One of the questions the staff posed was about whether we, the State of California or whomever is playing in this area, are providing adequate long term incentives for building new generation.

On of the concerns I've had for a long time, just looking at the economics and maybe piggy backing on Commissioner Geesman's investment banking experience is to me we haven't gone out very long as of yet, and without going pretty long, i.e. really long term in procurement, it is really hard to induce if not seduce investment community to engage with the applicants for new generation in financing said generation because we have such an uncertain future. Our hybrid system, which settled into the procurement process got modified somewhat by allowing utilities to build some of their own.

None the less, I didn't hear in your

comments, and maybe James this is primarily you, any indication of uncomfortableness or frankly comfortableness with our ability to attract capital to finance the new construction and what with the concerns about Southern California, I guess I get more concerned.

Any thoughts on that?

MR HENDRY: I think as I said in my comments with the utilities back being financially solvent, the utilities are capable of entering into longer terms contracts and have done so. As I said, Mountain View, Otay Mesa, Palomar are all examples of that.

Going forward, the Edison RFO, which is going out for ten years, so I think the utilities are capable of going to Wall Street and selling projects. The merchant sector, again, is looking for I think longer term contracts as well.

Again, it is a matter of I think the utilities can go to the extent they arrange financing from us, can then hold a procurement process that brings in competitive merchant generators who can then build based on receiving this longer term contract.

The ten years was, and there is

discussions about this in the procurement decision, you know, sort of seems to be the minimal amount that Wall Street is comfortable with. It is unclear if there may perhaps be higher financing costs for not going out longer. Again, it is the difference between sort of 15 year or 30 year mortgage when you buy a house. So, looking at longer terms of cost benefits is probably an issue that needs to be looked at.

You have also addressed the issue of the uncertainty from the hybrid market place, and as I noted in my comments, it is one of the concerns that the utilities have had in terms of their willingness to make these longer term investments, so there is a concern there. I think the utilities, now that they are back in financial solvency and with the guidance from the Commission and the procurement proceeding and with guarantees that under AB 57 that utility investments are guaranteed, you know, a reasonable opportunity of recovering their costs. It is clear the utilities can make these long term commitments for new capacity and that we are trying to insure an open competitive process so that all plant developers can have a fair chance to compete when those projects go out for bid.

COMMISSIONER BOYD: The 8,000 MWs that we have in reserve are heavily if not exclusively, and I don't recall each and every one of them any longer, merchant plants. Your answer is heavily oriented towards the utilities providing generation, and I guess I just leave that as a statement, that to me is somewhat of a dilemma that we need to address. We don't really have a reserve of utility proposed generation, and you seem to be banking heavily if not exclusively on the utilities. We still have a long ways to go I guess in dealing with this hybrid system that evolved. An observation.

PRESIDING MEMBER GEESMAN: Commissioner Pfannenstiel.

COMMISSIONER PFANNENSTIEL: Thank you, Commissioner Geesman. Just a follow up question really for James. On this whole issue of what is needed to bring those 8,000 MWs or the subsequent ones that will be coming through here into construction and then into operation, and am I hearing correctly that you think that really the process is in place now, that it is a matter of working off this backlog from prior constraints on utility financial position? Do you think the regulatory mechanisms are in place, that there is sufficient confidence in the California regulatory system that the financing will be forthcoming, or are you looking for further changes in the regulatory mechanism to make that happen?

MR. HENDRY: I think looking at the projects that we have approved and that have been going ahead, that Commission approval of a utility project which then may go out and contract with a third party merchant generator into purchasing the obligation or the siting from them is clearly a viable financing option.

You know, one of the Commission's main concern clearly is regulating the investor-owned utilities that we regulate and making sure they provide reliable service. I think my comments are mainly focused on what the utilities we regulate do. Clearly there is a direct access market in California, but it is probably this hybrid system which has 14 percent of the load, and one would expect that over time there should be projects developed that would serve that market.

I am not sure, I mean, various reasons have been offered as to why projects are not being built to serve that sector of the market, you know, uncertainty regarding financing, uncertainty overload, regulatory uncertainty, all those issues which I think, you know, have to be looked at some point.

Going forward one of the issues is when the Commission adopts its resource adequacy framework, which will then require all load serving entities, including the direct access customers and community choice aggregators to procure capacity under contract and 15 to 17 percent reserve is that may or may not -- we are hoping it will also provide incentives for those customers to then go out and say okay to meet this reserve requirement, the best way to do it is to go out and build new construction and that there will be sort of a meeting of the minds between the direct access service providers saying we have to meet this requirement to serve our customers and keep in business, and the merchant developers are saying here is a potential market first to serve, and the Wall Street financial community is saying this looks like a profitable deal for us to go forward on.

So, I think the resource adequacy

framework is one way this may be extended out to the entities not regulated, the entities that are not directly under the PUC's procurement process. Also, longer term there is the issue of capacity markets, which may or may not offer some sort of incentives for sort of the longer term investment strategy, and that is something the Commission has not weighed in on yet because we realize that is something that needs to be looked at and we are looking at pursuant to President Peevey's direction.

COMMISSION PFANNENSTIEL: Thank you. It seems like in about every forum on that these days, everybody is asking the question about why aren't plants being built in California, and it seems like every participant has his or her own opinions on that, so I was asking yours. Thank you very much.

PRESIDING MEMBER GEESMAN: Steve, I think you are next.

MR. GREENLEAF: Good morning, Commissioners and staff members. Steve Greenleaf, Director of Regulator Policy at the ISO.

Thank you for allowing me to be here today. I don't have any prepared comments today, so therefore, this will be mercifully short. With that, I would like to touch on just three topics.

I think as Jim noted earlier, the Commission has raised quite a number of very important issues, and I'd like to touch on at least three areas that I think bear on some of those questions.

The first is capacity markets, and I just want to reiterate a commitment and a statement that ISO CEO Yakout Mansour made at the June 2 technical conference on infrastructure development in California.

With that, Yakout committed to moving forward with an examination of the viability of capacity markets and developing capacity markets in California.

We do think capacity markets can be an appropriate and needed compliment to the resource adequacy framework that the state and in particular the PUC is forwarding and furthering.

Primarily for a couple of reasons. One is providing a means for LSE's be they large or small to satisfy the RA requirements established by the PUC. Secondly and just as importantly is to really equitably share the costs of maintaining resource adequacy for the state.

Third and bearing out a number of the issues here, we do think by establishing clear rules and a transparent market or reserves, for capacity in California, you can provide an incentive for future investment in critical energy infrastructure.

That is one initiative that has moved forward. I think it is important to clarify because I think subsequent to Yakout Mansour's comment, a number of people viewed that as somehow being in competition with the state or the PUC's efforts on resource adequacy, and we don't view it that way at all. We believe as Jim noted the Commission is presently examining the issue of capacity markets. Our effort we think can feed into that quite well and compliment that. In no way do we view this at all as kind of redoing or reexamining the issues that have been on the table and before the PUC over the last several years. I think that is an important clarification.

The second point I would like to make is with respect to transmission planning, and I think Commission Geesman you touched on a number of points that I think bear on this. Another initiative that certainly Yakout has interest in undertaking expeditiously is what he terms a proactive transmission planning process, and it has worked well.

Today's process really relies and builds off utilities submitted or PTO's submitted, Participating Transmission Owners submitted transmission plans to the ISO from which the ISO develops its integrated plan for the state. Yakout wants to be much more proactive in that sense, and perhaps this is what you were getting at with respect to an applicant driven process.

Yakout Mansour clearly sees the need for the ISO to step forward in the first instance and identify critical projects as indicated by a number of costs, in particular, congestion costs on the system today.

Yakout as far as I can tell intends to proceed this year with implementing that proactive transmission planning process, wherein the ISO will develop key projects and basically put those out for the transmission owners to incorporate in their plans or not. In the absence of them stepping forward with those projects, this process in our mind would contemplate putting that out and examining alternative ways to make sure those projects get built be it by third parties or what not.

Clearly the emphasis, we believe there is an important emphasis on expanding transmission development. That also bears in part on the issue of reliance on RMR and existing local generation. Clearly and appropriately, the PUC and as supported by the ISO is moving forward and establishing local deliverability requirements or local capacity requirements. Those inherently rely on existing generation today.

Whether they will provide sufficient incentives for new generation in those load pockets remains to be seen and bears on a number of other important issues and elements of the RA framework. None the less, transmission has to be a key consideration as an alternative to satisfying that. The local capacity requirements that exist today and that have been promulgated by the ISO are a direct consequence of existing grid topology and the constraints that exist.

Clearly the need is to examine not only whether it is appropriate to rely on local capacity or generation resources but also the transmission alternative. We think the ISO's proactive transmission policy going forward can do that and provide a benchmark or setting a bogey out there for consideration.

That bears on the third issue which is integrated planning. I'm not exactly sure where the home for that is today, whether that is before this Commission and the IEPR process or before the PUC in a long term procurement, but regardless of that, there has to be a renewed focus on integrated planning.

Jim spoke to a number of elements of that and spoke to consideration and diversification within the generation, just on the generation side, clearly there needs to be a weighing of the benefits, cost and benefits of going with generation or transmission. That is the key aspect of integrated planning from our vantage point.

Going back to the second issue, of course, the proactive transmission planning, we think can be key element or a key contributor and inform the integrated planning process that the state undertakes.

Lastly, as I recall the meeting notice,

the Commission asked whether and what legislative and regulatory action needs to be taken. Clearly in our view, the critical next step is for the PUC to move forward expeditiously and get the resource adequacy order out. We do have concerns based on the timeline, at least the timeline that we project. It looks like it is heading towards an October order which would mean the first demonstration for resource adequacy would not be until January/February of 2006 which causes some concern that as we head into summer 2006, we once again will be going in somewhat blind to the resource picture.

Now of course, you can rely on the monthly demonstration at that point, and that will be important, but none the less, the forward looking, the year ahead looking process is going to be key going forward, so more than anything, we would urge the PUC to move ahead expeditiously and get that order out.

I think that in part bears the answer to your question regarding the 8,500 MWs, and it really goes to the broader issue of regulatory certainty. I don't think the market will step forward. I don't think investors will step forward until there is a clear and stable set of regulatory rules that exist today.

It is not only what we move towards, it is what we move away from. I may steal Greg Blues thunder, I know he is in the audience, and part of that is the must offer. Clearly, if you talk to the suppliers out there and the investors out there, they would characterize the existing must offer obligation as a free call option on their capacity.

They don't want to invest, they don't want to put new steel in the ground or iron in the ground in that kind of regulatory/market environment, so I think it is absolutely key that the PUC get the resource adequacy order out there, establish rules that will be in place next summer so we can quickly transition away from the must offer environment. I believe Yakout Mansour referred to as both a blessing and a curse previously.

Clearly, must offer has been key for us to have the confidence that we can commit the necessary resources to maintain the system reliably in the short term, but we do have continuing concerns towards forward procurement and long term contracting that the must offer provides.

With that, I will conclude my comments, and I'd be happy to answer any questions you might have. Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Steve. I certainly welcome Yakout's arrival. I do think the ISO needs to be a lot more proactive, and although California regulators don't often agree with him, I think Pat would in his farewell interview got it right. We all deserve a D+ in terms of how well we have met our infrastructure needs in the four years since the crisis that we have had to work on that.

I think one thing Yakout is going to need to recognize is you get about twelve months before you start becoming more a part of the problem than part of the solution. He is pretty early in his tenure, so he's got some time.

I guess the concern I have as it relates to the ISO is both the persistence of unexpected congestion and the seeming permanent status of the RMR contracts. What priority does the ISO attach to addressing either of those two problems?

MR. GREENLEAF: I would pause it that

Yakout sees the RMR issue as playing directly into the proactive transmission planning. He is concerned about a continued reliance on not only just generation resources in particular areas and the obvious market power and other issues that arise from that, but also the continuing reliance on older plants and kind of limping along that we've done over the last several years. He truly does want to be forward thinking and look at congestion and just look at transmission import capability into the load pockets, be there significant congestion or not, he wants to examine that and seriously look at alternatives.

The flip side of course is you don't want to build transmission just for the sake of building transmission without consideration of the alternatives. In some circumstances, it may be appropriate to site generation facilities or rely on existing generation facilities. The manner in which you do that and the incentives you establish when doing that are very important, though. So, I think some of the RA rules, the compliance, the penalty rules under resource adequacy will be important.

It is not just the capacity market

structure, but the incentive structure, resource adequacy more broadly in place in other markets, especially in the East, they have acknowledged that by some of the demand curve approaches when they look at pricing capacity at the cost of new entry or two or three times the cost of new entry as establishing an appropriate incentive, either for new investment or for exploration of alternatives.

I don't think a RMR cost plus based paradigm really establishes or kind of furthers that cause. I think we need to move away from that. I do see them as going hand in hand.

PRESIDING MEMBER GEESMAN: In your more proactive approach, how do you see addressing or incorporating the state's preference for renewable sources of new generation? Those are technologies and projects where transmission access is likely to be a life or death question for the successful development of those resources.

MR. GREENLEAF: Yes, absolutely. I think Edison put forth through the trunk line proposal, you know, an intriguing concept I think has a lot of merit, but I don't have an answer for that. I think it is going to have to be done proactively but collaboratively with the state. Clearly, the ISO supports the loading order, but there are implications from that that need to be considered.

PRESIDING MEMBER GEESMAN: Thanks very much. Bob, you are up.

MR. KINOSIAN: Thank you. My name is Robert Kinosian. I am here for the Office of Ratepayer Advocates.

I'll try to keep my comments very brief and just touch on a few issues. First I would like to commend the Energy Commission, the ISO, and the Public Utilities Commission for their joint efforts which over the last couple of years, which I think have gone a long way to address a number of the issues raised in these questions.

Transmission planning is much more integrated now than it has been in any time in the past that I am aware of. Things aren't perfect, but we are improving things, and the discussion among the agencies really helps I think get everybody on the same page on these issues.

I remember having some of the specific questions that were laid out for the workshop today, the expense in recent years for the IOU's, the investor-owned utilities is that there is really no problem obtaining financing for their own new projects, of if they enter in to contracts with a generation company, that contract being used by the generation company to get financing for their projects. It is very clear given the response to the RFO's the utilities have issued in the last few years, which have all be over subscribed, that there is interest in building generation projects and financing available.

None of the projects that have won RFO's have ceased to go forward due to lack of financing except in a couple of real extreme cases that aren't worth mentioning.

Getting to the issue of the thousands of MWs of permitted but not built plants, one of the reasons is these have not been built is they literally aren't needed right at this moment. If those were all built right now, the IOU's would have a 40 percent reserve margin.

DWR probably to an excessive extent signed up gas generation in 2001, and all of those projects or most of those projects have been built giving the state a lot of new gas burning projects.

The state has now since then tripled the expenditures for energy efficiency programs and implemented the renewable portfolio standard, so a lot of new need is being met by those two resources rather than adding new gas generation at this time, plus we see a lot of excess generation being built in Arizona which will likely be tapped by the California market.

There are a lot of reasons why that 8,000 MW's hasn't proceeded at this point. Given that, though, there are probably a couple of specific issues that should be looked at in terms of getting some of that built to the extent it is economic.

One is having a resource adequacy requirement placed on the non-utilities, the non-IOU's for their needs also. The PUC has indicated that it is going to do that, but we know that there are legal concerns with whether or not they actually can impose that. While the direct access providers Sempra, Constellation are credit worthy companies can enter into long term contracts or build their own generation, they haven't done much of that at this point, and they should be required just like the IOU's to firm up their resources.

In addition, there is the specific issue about the old plants whether they should be retired or repowered. That is something that the Energy Commission and the PUC and the ISO should all focus on dealing with that issue and make the decisions, which of these should be repowered, which should be retired, and move on. The continuing uncertainty is a problem, and it is simply an issue that needs to be addressed rather than continually put off.

Moving on to a couple of the other areas, out of state coal has some potential for this state, but given global warming concerns and the availability of in-state resources, primarily renewable resources that we will be adding over the next few years, there does not appear to be a lot of room for a lot of new coal resources, at least in the next few years to enter into the California mix.

Definitely, there should be a policy that out of state coal resources must meet the same sort of environmental criteria, at least in terms of greenhouse gas emissions, that we would apply to in-state resources. That is a global concern, it doesn't recognize state boundaries or local boundaries.

Regarding transmission, as I mentioned before, I think the state has moved a long way to improving our transmission planning process. We see the need to get out ahead of the game and start planning for transmission resources well in advance of when they are needed because of the length of time it takes for the planning process.

I would note that for the most part, transmission lines, though, the long time needed is for the planning process before it comes to the PUC for siting and building. Typically the PUC proceeding only takes a year, construction usually commences a pace. The Path 15 line got built ahead of schedule.

It is really making sure that we get the initial planning done early like we are trying to do now with renewable resources and looking in San Diego's area to get more access to geo thermal plants and the Antelope project for addressing wind, we need to do that. Not at the point where we need these resources, but years ahead of time on the planning.

Finally, one other thing since I do represent consumer interests, one thing that should definitely be on the forefront of everybody's mind is the cost of all of this. Rates are a real crisis right now. They are incredibly high, it is a huge problem.

If you had said ten years ago residential customers were going to be paying 25 cents a KWh, I think that most people would have thought that we already had time of use or real time pricing rates in place, but that is the standard rate for Tier 4 customers, which is pretty much all the customers who use air conditioning.

We need to look at getting cost down, not just at improving the infrastructure and the reliability. One thing that the state should consider along that lines is something that was used recently in the PG & E bankruptcy case and was used a few years ago as part of restructuring is dedicated rate component financing where we can get five or six percent carrying charge on new capital investments versus the 20 percent cost of utility rate base or similar costs that are built into contracts with third parties. That would be one way to greatly reduce the cost to ratepayers of added infrastructure.

That will conclude my comments.

PRESIDING MEMBER GEESMAN: How does ORA address the fuel component of our electricity supply system, which seems to be an increasingly large element on customers bills? You seem to focus on our regulatory process and seems to focus largely on capital expenditures, applications for CPCN's, return on capital investment, and fuel costs seem to just be a pass through. They keep going up, you know, in our 2003 cycle, we forecast gas prices in the low to mid $3.00 range for the entire forecast period. It looks like we are off by about 100 percent. The discovery that we were off by that much, and everybody else was, we weren't' alone, but the discovery that we were that far off doesn't seem to have prompted any kind of searching review of maybe we are headed in the wrong direction. How does ORA look at our natural gas dependency?

MR. KINOSIAN: As I mentioned earlier, I think there is a considerable concern that the resources that have been added in the last five years largely in response to the DWR contracts are almost entirely gas fueled, and ORA is very supportive of the RPS standard, and we are hoping that the Commission will aggressively implement that. In fact, I have raised concerns to the Commission about how much they have been dragging their feet on getting the renewables built and they need to aggressively pursue that.

As I did mention before, one action that the PUC has taken with the support of ORA has been literally tripling the budget. We are now spending almost half billion dollars a year on energy efficiency programs versus just roughly 100 million dollars a few years ago.

This is in direct response to both electricity prices but also high natural gas prices. We are also very supportive of the recently announced efforts to reduce greenhouse gas emissions which we think will further push or reduce the reliance on natural gas as a resource.

So, we think there are a lot of things under way and in the mix to reduce that and ORA definitely recognizes the impact high gas costs have on customers. We are also greatly increasing our spending on energy efficiency for gas customers and reducing gas use, not just electric use.

Our natural gas rates are tied to

basically a monthly short term cost of gas, so customers see that directly and respond accordingly. A number of efforts are under way. Could more be done? Sure, but things are being done. It is not an issue that is lost on anybody.

PRESIDING MEMBER GEESMAN: Thank you. I think it is time for any audience questions or comments to this first panel. People are shuffling in their chairs, but I don't see anybody jumping up to the microphone. It is a rare and endangered species the microphone.

MR. SCHLEIMER: Commissioner Pfannenstiel, Commissioner Geesman, Commissioner Boyd, I just have a couple of comments. My name is Steve Schleimer, and I am Vice President of Regulatory Affairs for Calpine.

One of the questions was about the 8,000 or 8,500 MWs and how we get that built. It seems to me that the answer to that is pretty simple, and that is to get more RFP's out the door.

I don't think it is going to take anything more than that. Right now generators are not going to build for the merchant market. Ten years is probably appropriate, ten year contracts, but depending on the circumstances, five year contracts, seven year contracts may be adequate as well.

One of the questions, though, I think we need to answer is, and it was referred to earlier, is the question of direct access and community choice aggregation and how we deal with the capacity associated with those.

Currently it sounds like direct access is about 15 percent of load, community choice aggregation is starting to move forward. My understanding is, although I don't know the details because I wasn't able to see the actual data, was that in the utilities resource plans, there are thousands of MWs that are missing from what they are planning for.

Basically what they have done is they forecasted their load over a certain period of time and they have subtracted out from that assumptions about current and future direct access as well as community choice aggregation.

My guess is that could be 5,000 to 7,000 to 9,000 MWs over the next ten years, and that is an amount of MWs that nobody is planning for right now. I think that is a key question that we need to think about answering is how are we going to get the capacity built for those resources because I think right now most folks would agree we are right on the edge or we are a little bit short.

As loads start growing and the utilities are acquiring for only a portion of the loads in their service territory, we are going to always be behind for the next ten years. It seems like we are never going to get caught up. I think we need to identify how much is that load that no one is planning for, and how do we get the resources built for those.

One way, Turin has suggested during an interim period that either the utilities or the ISO be a backstop provider of capacity. You know, there are other ways that you can do it, you can have the resource adequacy mechanism go for five years instead of one year. The resource adequacy in the capacity markets is a good step, but having it be a one year ahead product or market, is not going to get capacity built for these resources.

The only way you are going to get capacity built for these resources is to have a multi-year either resource adequacy or capacity market.

PRESIDING MEMBER GEESMAN: Steve, are

you guys responding to all of the RFO's. I was at something in Silicon Valley a month or two ago where Pete Cartwright had indicated concerns about the way some of the RFO's were structured hoping to incent new construction having the perverse affect of borrowing some of your projects that don't have contracts from participating.

MR. SCHLEIMER: Both Edison and PG & E have ten year RFO's out. Those ten year RFO's preclude existing resources or resources actually in constructing from participating. We did not bid into those with our existing resources, but we have bid into both those RFO's with new generation that we have permitted.

In fact, we have four, five, or six combined cycle plants that are fully permitted pretty much ready to go awaiting contracts, and we have bid those in.

Edison just came out with their five year RFO, and we would expect to be participating in that one as well.

PRESIDING MEMBER GEESMAN: The Metcalf plant for example, you are selling that into the market currently?

MR. SCHLEIMER: Yeah, we are selling

that into the market. We currently don't have a capacity contract for that facility.

PRESIDING MEMBER GEESMAN: Thank you. Other comments or questions from the audience? Greg. Bad choreography? Okay, then we should probably go on to the next panel.

MR. GALLOWAY: I am responding to what they are saying. I can talk now or I can talk later.

PRESIDING MEMBER GEESMAN: I think Karen who is the MC says later.

MR. GALLOWAY: Later is fine. I don't want to miss my opportunity.

PRESIDING MEMBER: I assure you that you want.

MS. GRIFFIN: Thanks to our first panel, and can we bring up the second panel. I know that two of the folks are here, Kevin Woodruff and Jerry Jordan. I am hoping that Jan and John are here as well, so please come on up. Can we just go in the order you are on the agenda starting with John Galloway from UCS.

MR. GALLOWAY: Thank you for the invitation to be here, Commissioners and staff. It was interesting I was watching a program last night on California's Gold Rush back in the mid 1800's, something that not being a native Californian I wasn't all too familiar with, but something struck me about half way through when they started exhibiting the environmental damage that was done during the Gold Rush and trying to get at the minerals under our soil, and I began to look at how that might be a parallel between the prospectors of about a century and a half ago and prospectors that are now spying the promise of a new resource in California which is home for their coal fired electricity.

This post modern gold rush for energy also comes with an environmental price in terms of air and water pollution. Then I ask the question do we want California to lead the west in becoming the new frontier for global warming. The governor certainly doesn't think so nor do I, but the allure of clean coal, a term that has recently entered our common vocabulary here in the energy arena, kind of like terms like resource adequacy and capacity markets, but has yet to be satisfactorily defined, raises and issue that appears in today's agenda, the affordability of supply. That is just one of many issues that it actually touches upon.

There is a very valid concern throughout the US and especially in California about rising energy costs. We have to balance that concern against the long run costs of doing business as usual and increasing our reliance on imported fuels.

I will put new coal development into that last category as we are seeing an unprecedented number of new coal plants being proposed throughout the West, which are being touted as low cost reliable domestic resources.

So, I would question the low cost aspect of that picture because the projected cost of new coal ignore the long run impacts of global warming emissions associated with the operation of those plants.

Leaving those impacts aside for the moment, I would like to pick apart a question posed on the agenda regarding the technology risk incurred by the state if "the best available technology is required", and so I was a bit confused by that term because it is traditionally reserved for pollution control devices that don't necessarily address carbon emissions. So, I will assume that term refers to technology such as IGCC and carbon sequestration methods.

I would like to turn that question around somewhat and ask what is the risk to the state of not requiring the best practices for abating carbon emissions from new coal plants. Indeed, the Public Utilities Commission has already identified and quantified the financial risks to utilities and rate payers of carbon emissions by adopting a carbon adder in its December procurement decision and later setting that price at a levilized value of $8.00 per ton.

I would like to broadly outline what I think we need to be thinking about when we talk about clean coal. First because of the fuel cycle impacts and the range of environmental risks, energy efficiency should always remain the top resource priority as particularly called out in the state's loading order, followed by renewable energy, and finally fossil technologies with the best available technologies.

To the extent that coal is utilitized, the best available technology should be used and long term carbon risk should explicitly be considered and allocated. I would like to emphasize Mr. Kinosian's earlier point about counting coal's emissions both the same, out of state coal emissions the same as we would count any resources within the state. Indeed, greenhouse gases don't necessarily respect state borders.

I would add to that we have not performed as an organization. UCS has not performed a detailed coal technology analysis. We are in process of doing that, but it generally appears to us that IGCC or Integrated Gasification Combined Cycle with some form of carbon capture and storage is the best available technology for coal.

While there are varying views among environmental groups regarding coal and what requirements should be made for the best available technology, one position clearly emerges. The conventional coal technology in California's resource portfolio is unacceptable.

In addition to the carbon emissions, the IGCC and equivalent technologies, whatever those may be or whatever technologies emerge, are needed to address all criteria pollutants including SOx NOx and mercury with mercury being especially important. Again, it sort of harkens back to the Gold Rush days where mercury was a significant pollutant in the process of extracting gold.

I would caution against the use of offsets at this time. In other words, if somehow we could abate carbon emissions through other means like planting trees and continue to build the coal plants until we have a well defined national cap and trade program.

I know we are going to touch on that topic more in our workshop in mid August which I appreciate you all scheduling that discussion in the IEPR process.

Moving on to other topics, earlier, Commissioner Geesman, you mentioned the Tehachapi line and there was a bit of discussion about the trunk line proposal and the potential problems with that. I guess I am a bit concerned that the PUC seems to be relying on getting FERC approval for that line, and there doesn't seem to be a back stop plan for addressing what happens if FERC either rules against that line or if it rules in favor of that line and it then goes to court and becomes challenged.

PRESIDING MEMBER GEESMAN: We are at the

back stop, FERC disapproved it.

MR. GALLOWAY: So, we are at that stage. I'm intrigued by the idea of looking at resource clusters, and again, Commissioner Geesman, you brought up the point or the question to the PUC about application specific transmission facilities, and I would ask why we aren't looking more diligently at this stage at specific resource clusters along the trunk line concept and identifying where those resource clusters are. I have yet to see all the agencies, namely the PUC, CEC, and the ISO sit down and specifically tackle an analysis of those resource clusters. I am pleased to see the recent joint agency efforts such as the kick off of the Energy Action Plan 2 discussions that we have had around demand forecast in this state. So, I am hoping we can continue that joint agency effort around transmission specifically to access renewable resources and get to our EAP goals.

Another point that is on today's agenda that I was a bit confused about is the categorization of issues into generation resources and transmission, so I would encourage that in discussion supply-side resources that we don't forget demand-side resources and the need for utilities to consider those resources as an integral part of their procurement.

Energy efficiency technologies can be the deployed quickly, provide significant environmental benefits compared to drilling, transporting, and burning natural gas. I would say the same goes for coal as well.

It can begin to reduce demand for natural gas the moment they are put into service. Those same benefits are delivered by renewable energy resources on the supply side.

The final point I want to make is that we should establish statewide goals for efficiency in renewables. A substantial amount of attention has been placed in recent years on the investor-owned utilities and establishing energy efficiency and renewable targets for those entities, and we need to keep our friends at the municipal utilities in check with respect to these resources.

With that, I would like to thank you for the opportunity this morning to speak.

PRESIDING MEMBER GEESMAN: Thank you for being here, and I admire what you are doing. I will say, and I don't begrudge anybody occupational mobility, but the RPS program has greatly suffered since you left the PUC, and I think that you and USC and the other I guess they call them non-market participants in PUC vernacular, you ought to expect more of us. I know a lot of you are imbued with how great it is to see the agencies working together and talking with each other and pretending to be friends, you ought to have I think a much more cold hearted assessment of what products is that process actually producing. What are the tangible results, and do they in fact meet the objectives, the legislation, and our various policy pronouncements laid out for us.

It was a long time ago, and in fact, Jerry Jordan was a young man, but I was an opponent of utility power plants once upon a time. I will say it is a lot easier to be against something than it is to be for it, and I think your real leverage over time in achieving that the end results that I think UCS wants to achieve is more likely to come from your ability to successfully get us to do things like the initiatives in energy efficiency and like the renewable portfolio standard.

I would encourage you to take a pretty harsh view of progress today. We need to do a lot more, and hopefully in the months ahead, we will do a lot more, but we very much need your pressure to accomplish that.

MR. GALLOWAY: That is appreciated, and I appreciate the earlier compliment, and I am out actively recruiting.

PRESIDING MEMBER GEESMAN: Kevin, do you want to go next, or actually, we are going in the sequence here. Jerry.

MR. JORDAN: First of all, I have to admit that I haven't actually read every single word that you've written as part of this year's Integrated Energy Policy Report, but it appears to me that you may be missing the biggest of the big questions.

That is whether or not the current market structure which we have either forced on ourselves or inherited from a set of bad circumstances actually supports the kinds of things that you are asking about in this document.

With that, I mean, it may in fact be and probably is our belief that the market structure that is set up a) doesn't work, and b) certainly doesn't incentivize either the building of transmission or power plants in this state.

We think it would be good for the Energy Commission to do a critical analysis of whether or not that structure, and with that I would include the entire concept of the independent system operator and how it functions and the assumptions that go into that.

For instance, a lot of the things that I heard today, including renewables, seems to me would work better in an environment with physical transmission rights rather than derivative financial transmission rights. As you may know, local agencies haven't been very fond of derivatives since Orange County had a problem. So, there are some basic structures there.

We have a system, the Energy Commission I think in the last policy report and the Public Utilities Commission have both endorsed a return to direct access, yet we don't know that is going to occur. We don't know what the status, in fact, is. The way the current law reads, I believe once the DWR contracts are paid off, direct access may come back.

Yet, the PUC has proposed that be implemented with an exit fee that may mean that nobody has direct access. Our market structure that we have in place now was primarily designed to serve a market structure that involved disaggregated utilities which we sort of have and sort of don't have anymore.

It was not specifically even attempted to serve the interests of utilities who chose to remain vertically integrated. Yet most of the utilities in the western United States, in fact, have remained vertically integrated.

A lot of the reliability issues that you questioned, for instance, are really regional reliability issues better suited to resolution by the WECC than either the Energy Commission, the PUC, or even the ISO.

We think you've missed the biggest of the big issues, and I would be happy to talk about some of those later on.

PRESIDING MEMBER GEESMAN: We don't get a clean sheet of paper, though, you have to play the cards that you are dealt. We are not going to be able to redesign a market as various idealogues would like to have it.

MR. JORDAN: Certainly, but we are idealogues on one side and Mr. Blue is probably idealogue on the other side, but your function in preparing this report reporting back to the legislature would seem to me to be to critically assess whether or not that structure is actually working to the benefit of California consumers.

I realize that it would still take legislation to make any changes, but we ought to at least know whether or not it is achieving whatever goals are still out there. I'm not sure we even know what the goals of the organization are.

PRESIDING MEMBER GEESMAN: Thank you. Okay, Jan.

MS. HAMRIN: Okay, thank you very much for inviting me. I also have not read all of the pages of material and reports that you've put out, and we have not been intervenors in any of these cases, so I am speaking more as an observer from the sideline and working on ancillary issues.

To me, the top issue and one of the questions is what are the top electricity issues. I think it is how to achieve greenhouse gas reductions while keeping the lights on and keeping rates affordable. One of the big barriers I believe is not a policy barrier or problem, it is more mindset.

I think that maybe our decades and decades of working in adversarial proceedings has ingrained in everybody of them and us kind of approach whether it is the CEC versus PUC or IOU's versus consumer groups or renewables versus fossil or whatever.

I think in this particular case and at these times, we should not be looking at it as a zero sum gain, but rather something that either we are all going to win or we all going to lose. There's tons of big issues in the world that most of us can have no effect on whatsoever. We can be concerned about them, we can send checks off on occasion to various charities to work on certain things, but that is about the most we can do, and we can cringe when we read the morning papers or hear the news.

Climate change and the issues that are facing us today are something that every person in this room and everyone listening can have a role in fixing if we have the will to do it. Instead what we tend to do I think is look at all of these things in pieces, not integrated.

We still have a tendency to have renewables and efficiency treated as oh by the way, there's also the renewable efficiency piece. I think it is important that instead of having people come with all the excuses of why they can't do these things, we need to focus on as I think you were trying to do in this workshop what are the solutions. You can't bring me a problem if you don't bring me a solution.

The long term and the short term are constantly in battle with each other, and so there is a tendency for us to make all kinds of exceptions for short term expediency, that means we never get to the long term solutions.

I think the loading order is great, I think you have it right, efficiency renewables than cleaner fossil resources and others, but if you are going to start the whole loading order implementation by having exceptions to it and therefore, the first thing we are going to do is put into place some fossil plants that we just have to have in the short term, and then we have to do some other plants, fossil plants, that are already signed up to be constructed, we never get to that loading order, a first efficiency, and then renewables.

If we have a policy, then you need to stick with it, and you need to apply it uniformly. I think, again, one of the problems with RPS and with the general approach we have is that it starts to be viewed as this is a ceiling. It is not a floor, it is a ceiling, and there is a tendency for people to say we are not going to do one MWh more than we have to or than you force us to do.

In fact, I think everyone in this room if they really wanted to achieve these goals could think of some ways that we could do it that would be beneficial to the companies whether they are municipal utilities, investor-owned utilities, generators, or non-residential customers.

There are ways of doing this, and there are ways of going beyond the targets that we have in front of us if you think positively and collectively in a can-do way. That is the way that this state used to think or we tried to approach things. I think John alluded to a couple of these concerns when he spoke, there are positive ways of doing it, and we can be a model.

I think that voluntary markets are another area. Green pricing is an opportunity for all of the IOU's that we haven't looked at that can allow them to go beyond what's required. I think there is opportunities to build plants and then incrementally add capacity to serve some other needs such as building plants through the procurement process for the RPS and then adding a little bit of extra capacity on to those to serve green pricing markets, to serve CCA's Community Choice Aggregation markets as they develop, to serve non-residential voluntary markets where we've got amazing response from many many corporations, industries, and institutions in the state and around the United States who are voluntarily looking at purchasing more renewables.

Common wisdom a decade or less ago was that nobody will pay one cent more than they have to for electricity, but we are actually seeing that there are customers who are willing to pay a little bit more and who think is an important task.

To the extent that our utilities and others can't offer those services, I think they will benefit financially and the state will benefit in a substantial way both environmentally and economically.

The municipal utilities have done some excellent work in a number of areas. They have had some very innovative distributed generation programs for photovoltaics, they've had some interesting green pricing programs. There are some number of ways that we could learn from some of the good things the municipal utilities have done and apply those to investor-owned utilities and vice versa, but we again we have a them versus us kind of thing that separates the two off, and that often prevents us from learning from each other and applying some best practices in the other areas.

I think that the challenge, the real challenge is the transition strategies in how to meet our long term goals and long term investments and long term objectives and do that with the short term in mind. I know that is difficult, but I have no doubt that everybody in this room again or listening could come up with some good ways of resolving it if they looked at the challenges, a positive thing that they wanted to accomplish rather than a negative thing they have been told to do and therefore going to find all kinds of excuses for not doing it.

Thank you very much.

PRESIDING MEMBER GEESMAN: Thank you, Jan. You have done quite a bit of work with the Chinese government in energy. Could you describe what role you played there and what projects you may be working on?

MS. HAMRIN: I've been working in China for five and half years, primarily on renewable energy policy and energy efficiency policy, and the last two years worked with them in the development and passage of a renewable energy law, national renewable energy law, and are now working with them on the implementation of that law.

One of the things that I've really learned in China, I've had a number of people I've taken over with me who have sat in the National People's Congress or in meetings such as this held by federal agencies, and afterwards have said my god, the Chinese are going to take over the world. They very well might.

I don't know if in my lifetime, but certainly in the lifetime of a lot people in this room, to the extent they do, it is because they have this can do attitude. They do not sit and whine about necessarily we can't do this. Instead they say how can we do it, tell us how we can do it better. They look for solutions and they put them into place. We may not always agree with all of the actions they take, but they are action oriented. It is part of the culture, but it certainly been part of the culture in this state and in the West in the past, and I think it is one that we could all bring back into play and would help a lot.

PRESIDING MEMBER GEESMAN: To an outsider, they appear to be aggressively pursuing all sources of energy. Can you cast any light as to how they prioritize between efficiency and renewables and coal and nuclear and oil?

MS. HAMRIN: I don't think they've got that down yet too well. They have huge growth, economic growth and growth in the electricity industry, and somewhere around 12 percent a year.

They are having a hard time keeping the lights on and keeping up with demand. They have a society that is just starting to use refrigerators and air conditioners and all of these electrical appliances. In looking at that, they started with efficiency standards, and many times efficiency standards that are not stricter than we have here because they recognize that if everyone starts buying, everyone who can afford it, and there are a lot of those in China, starts buying refrigerators and air conditioners, and all of these appliances, they really won't be able to meet their energy needs.

They have also done a similar thing in transportation, and they have cafe standards for vehicles that are much stricter than we have in the United States, so they have done a good job in setting those.

Enforcement is something they have a lot of work to do, and how you can enforce these things, they haven't always had a lot of options between ignored entirely or take somebody out and shoot them, and though the last has its attraction on occasion, I think they are just now looking at civil law and ways of doing enforcement a little bit better.

They have also closed a bunch of coal plants that ignored environmental standards and went forward anyone, and that was definitely a signal from central Chinese government that they were taking the environment seriously.

The bottom line is they see real costs. They have seen a loss in agriculture production of over 30 percent. That is a real loss for the country. They have seen increases in medical costs especially due to respiratory infections and so forth of a significant amount.

They are seeing those not just as altruistic or idealistic goals, but as real costs to their economy that they have to address, and they have to do something to get this under control sooner rather than later.

PRESIDING MEMBER GEESMAN: Thank you very much. Kevin, you are up.

MR. WOODRUFF: I appreciate the chance to address this Commission on some rather critical electricity policy issues that face this state. I think a lot of us could go on for a long time about the details of the 14 questions that were posted on the website for this meeting. I am going to confine my remarks to the first three questions on generation resources in particular, and then touch a little bit on the first three questions under transmission.

On the first question under generation

about how to incent new construction to paraphrase it, you've already heard a lot of what I'm going to say, but I am going to say it again anyway with my own accents and spin on it, and I agree fully with some other prior speakers of the key impediment to getting new projects built in California in the current market environment is the lack of long term contracts, and before I go further, when I say long-term contract, it could mean a contract with an IPP for the output of a plant that would allow the IPP to go finance the plant or utility owned resource under the traditional regulatory compact where the utility would have good confidence it would recover its costs of building and operating the plant.

I'm including both of those options under the term "long-term contract". Mr. Hendry mentioned the irrational exuberance of the late 1990's, it is a line I've used myself about that time. In that era, of course, there were a lot of players, some are now gone, some don't have credit worthy ratings any more, but there are a lot of industry players that took on merchant risk and allowed projects to be financed and built.

That is not happening now, and it may

happen again, but it is not something we can count on to happen if we want to have a regular construction cycle in this state of new resources to meet loads that I would anticipate to keep growing.

What you need to do in a down economy like ours that has happened and will continue to happen to occur is long term contracts. The problem right now is that load serving entities are generally unwilling to make those long-term contracts because they don't know if they can recover the costs they are going to commit themselves to.

This is true for the IOU's that don't know about their load, to what their load is going to be, and it is true for the other LSE's that also have substantial uncertainty about their own loads.

We suggest in general policies as has been said before, the policies that will provide LSE's some certainty about what their loads are going to be over the long term and also require them to make some long term commitments under a resource adequacy policy are necessary to get new projects built.

Now what won't be sufficient is the current one year or less type of commitments the LSE's are going to make under the RAR policy to be adopted later this year by the Public Utilities Commission, a one year look ahead is not going to be enough to get something built. Any new sort of capacity market that has a similarly short horizon, whether it is seasonal or annual, is going to have only a marginal impact as well.

I will also add that regulatory certainty has been touted as a good thing, and it is, but that in and of itself is not going to be sufficient either. What are needed are long term contracts.

Now, this may sound like a gloomy message, but you know the glass is half full at least. The IOU's, the state's three major IOU's between them have committed to fund development of some new generation. PG & E and Edison both have long-term RFO's on the street right now that their management has said have been pretty well subscribed, and there may be some I think winners announced on both of those processes later this year, so things are happening.

It is not that we are at a complete

standstill right now. We don't want to give that impression to the world or make decisions based on that impression, but until we know that representatives of all loads are actually making new investments, we can't say that within the aggregate we are going to have a reliable system.

The second question that was asked had to do with whether the 15 to 17 percent reserve margin is adequate. I would suggest in general that it is. It is a very simple answer. I think Mr. Hendry again gave a fairly good concise recitation of how that came about. I think a 15 to 17 percent reserve margin over an average or a one and two load is perfectly adequate for aggregate system wide reliability.

When you are looking at local regions, you might want to move to a higher load forecast like a one in five or one in ten, but when you are doing that, you don't want to apply the same percent reserve margin on top of that. Instead, what is done is on top of that higher load forecast, you layer a reasonable number of MW contingencies to come up with some MW resource target that provides reliable service within that load pocket.

Before the generators get too excited at that prospect, it is quite possible for that analysis to come up with a planning reserve margin in effect that is less than 15 percent. It could be more, it could be less. This local area reliability planning is a somewhat different animal because you don't have the loss of load probability, the math breaks down when you have smaller systems.

The methodologies that are used to assess local reliability don't always give you numbers that are higher than 15 percent. That is something that needs to be kept in mind moving forward.

I spoke to this Commission, at least Commission Pfannenstiel and Geesman were here in March when I mentioned I really didn't care for the kind of resource analysis that is being presented to the Energy Action Plan Committee. I don't think that is an appropriate long-term planning tool because you cannot meet the criteria that are apparently there using a 15 to 17 percent reserve margin. We are never going to get there under resource adequacy policy, but I think you raised a very important point, Commissioner

Geesman, in talking to Mr. Hendry or it might have been Mr. Flynn, on the one hand I am not that worried about SP 15 loads and resources this summer in the aggregate. I think if we are going to have problems in the SP 15, it is going to be because of intra zonal transmission issues, and I think there is evidence that was in the public domain last year that pointed to that possibility, but I didn't really see those issues being developed very well and solutions being proposed for particular pockets within SP 15.

It is critical to look at those kinds of issues and separate from the aggregate because you can buy a resource in SP 15 that will do you absolutely nothing for reliability in the region if the problem is going to be intra zonal transmission constraints. You need a more focused analysis looking at transmission fixes or maybe the acquisition of some very specific resources and very specific load pockets.

That is what is needed, and I didn't see that happen last year despite I think ample evidence in the public record that the problem really was -- the problems last year and I think most likely this year were local transmission related.

We also believe that the 15 to 17 percent reserve margin is economically sustainable as the question is asked because it is in line with historic industry practice. People are used to paying for that much reliability and receiving that much reliability.

When you say economically sustainable, do you mean if that can be supported necessarily by market prices without some sort of resource adequacy requirement, I wouldn't count on that necessarily. Even with a new capacity market or with uncapped energy prices, it is not necessarily the case that planning reserves of 15 to 17 percent would be supported by market revenues. That is a fairly major assumption.

There can be a fairly big disjunction between the financial incentives the LSE's face and the physical assets needed to maintain a 15 to 17 percent reserve margin. I think the state has addressed that appropriately by focusing on a physical resource adequacy requirement and making the LSE's go out and make sure they have the capacity to meet that requirement lined up.

I want to focus briefly on one topic in

the third question which has to do with capacity markets. I've already said that if you are just looking at short term incentives, their impact will be marginal at most. I think in general it is utterly impossible to say what kind of impact they would have until you actually implement them. Whether you find god or the devil in the details is going to be rather critical.

Capacity markets could well help load serving entities that are long and short of their resource adequacy targets. It helps them manage what you call the quantity risk, and they should provide some extra revenues for some of the marginal generation that doesn't run much to be around.

What concerns me the most about capacity markets at this point is that people view them as some sort of cavalry that is going to come and save us. They are not, they are just another tool that might have a place in a long term resource adequacy policy. Again, if it is just a short term capacity market, you can't count on that to provide incentives for long term construction or more than marginally so.

In particular, capacity markets do not

protect load serving entities and their customers from price risks. In other words, if you pay a price for capacity product today, you have no idea a year of now whether the value of that investment is going to be higher or lower.

I raise this issue in particular from something that is close to TURN's heart of course which is stranded costs for new IOU investments. There is absolutely no guarantee the capacity markets will eliminate or even greatly reduce the stranded costs risk that bundle that ratepayers face.

I think those are important caveats to keep in mind as the state moves forward with developing capacity markets.

Finally, I just have a few words on transmission. Again, much of this has been said, but I will say it again to add TURN's voice to this, to the wood pile. The questions one and three ask implicitly if new transmission is likely to be profitable or needed or cost effective or needed, and the answer is TURN is certainly open to that possibility. In fact, in many cases it is probably a likelihood, but each proposed deal needs to be evaluated on its own, especially the large projects that are driven by economics.

Then another aspect of question three asks about how to make transmission, how to make sure it is made in an on-going routine basis, and again, we need some sort of better routine process. PUC President Peevey issued in a signed Commissioner's ruling in October suggesting that this process would be developed through some sort of open and public process. That hasn't happened yet, I think that is something that does need to be developed in the near future. In particular, it needs to be integrated with generation planning.

The second question that was issued asked about the delinking of generation in transmission planning. I think that has had some negative consequences that can be resolved if we tie the two processes back together again.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Kevin, particularly for those last remarks because I think you are on to something there that we need to explore further.

On the question of uncertainty about future loads and who the utilities customers will be, we got into this same dialogue a week or so ago with Scott Kushwaf from ORA at one of our earlier workshops. I asked him and I want to ask you the same question, whether the CPUC's December's decision which made very clear or at least attempted to make very clear the PUC's intent to attach exit fees in such a way that no cost shifting would be allowed. Whether that provided adequate certainty to the utilities to quell their concerns about the uncertainty of who their customers will be in the future.

MR. WOODRUFF: Yeah, I was here for that meeting, and I thought that was actually the best part of the day when the panel talked about those issues. I think that would help provide them some substantial help. I am not sure it addresses all their issues as Scot Kushwaf mentioned, they still face the issue of customers coming back when based upon what happens in the power markets and paying potentially higher spot prices to meet the needs of those customers. There is still some uncertainty coming back.

I guess I would be concerned, even though TURN supported exit fees in general in the proceeding that led up to that decision, I just have a little queasiness about sort of their long term viability and application. I don't think they sort of resolve all of the issues entirely. Just to say that we have exit fees, there is again the implementation to consider and the longevity of that as a policy. Yes, it is a partial step.

PRESIDING MEMBER GEESMAN: How would you address the concerns about returning customers?

MR. WOODRUFF: The Commission had -- you are getting into an area I don't know very well some of the details very well, the Commission, the Public Utilities Commission just about two years ago issued a decision on so called coming and going rules.

I know some of the IOU's and possibly my client was not involved in that proceeding, thought this might have been a little too lenient or too flexible. That would be one area to look at.

PRESIDING MEMBER GEESMAN: Scott actually preponderate the view that once you are gone you are gone. Do you have a reaction to that?

MR. WOODRUFF: That is an interesting policy and theory. I'm not sure you could actually enforce that in practice. Again, one reason that we are looking to the IOU's to build now, to finance construction now is because they can and no one else really can. If you have a lot of non-core load that leaves and thinks it is gone, that may be fine, but a few years down the road, you may come into a situation where they really need to be served, and the IOU's are the only ones that can serve them. I'd be concerned about being able to enforce that kind of a policy over the long run.

PRESIDING MEMBER GEESMAN: Okay, and then the next step is if they do come back and the IOU's do have serve them, they can be served on an incremental cost basis for some period of time. Do you have a reaction to that?

MR. WOODRUFF: I believe that is part of the Commission's coming and going rules now, at least for some period of time. The challenge there is -- there are a couple of challenges there, one of which is surmountable in practice which is defining what those incremental costs are, but you can impose that policy. The bigger larger issue, though, is if the system is really short of resources, if it is not just the prices are high, but there is actually the state has allowed itself to get short, you may not be able to serve them at any price, assuming no one else has asked to curtail.

Given the way the grid is designed now, blackouts or rolling outages tend to be done on a randomized basis, and it is not clear you could necessarily serve them reliably.

PRESIDING MEMBER GEESMAN: Now one of the benefits of advanced metering claim to be the ability to have targeted outages. TURN has not been among the most exuberant fans rational or irrational of advanced metering.

MR. WOODRUFF: Yeah.

PRESIDING MEMBER GEESMAN: Would you see that as perhaps a hidden benefit of the advanced metering initiative?

MR. WOODRUFF: Again, I'm not -- I don't have all the details of advanced metering, the advanced metering case. What would concern me in that case also is, again, five or ten years down the road, are the state's political leaders really going to say to a major industry, well, you have signed up for this, you know, you have to shut off. That could be a deal that would make sense to the state and to everyone involved now, but five or ten years down the road, the owners of that business have a fiduciary responsibility to their shareholders, and they are going to try, assuming they are a profitable business, still try to keep their power coming in, and I don't blame them for doing this.

I'm not being critical, I am being realistic here. They are going to come and try and keep the power flowing to them. I've seen cases where businesses before have looked at a contract that was signed ten years before and say, what were we thinking, you know, what was that guy thinking when he signed that. That would concern me about that kind of assumption as well.

PRESIDING MEMBER GEESMAN: Thanks very much.

MR. JORDAN: If I could, I'd like to comment on the exit fee issue. You know, it would seem to me that sort of an exit fee is really designed to make sure that the investor-owned utilities don't lose any customers to those sources. A better way to handle that would be for the Energy Commission, which has the expertise to forecast what are the likelihood of how much load leading in the current situation, community choice aggregation and direct access being in suspension, as one of my utility managers said, even if you include annexations by existing municipal utilities, you are probably talking less than the IOU line losses.

PRESIDING MEMBER GEESMAN: I'm not certain I agree with you in terms of the expertise necessary to be able to forecast --

MR. JORDAN: You used to have it.

PRESIDING MEMBER GEESMAN: You used to be a younger guy too.

MS. HAMRIN: Could I address one substantive issue I didn't mention briefly?

PRESIDING MEMBER GEESMAN: Yes.

MS. HAMRIN: That is the deliverability requirements for renewables. I think it would be useful to look at what the public interest goals are of those requirements to see if there is some other options for meeting those goals because I think in many cases they can be a direct detriment to the ability to bring renewables on line in the state or meet our RPS requirements or other things. I think the important part is not what the rule is, but what was the purpose of the rule and whether there is some other ways of getting there so it doesn't have a negative effect that it might be having now on some development.

PRESIDING MEMBER GEESMAN: I think that is a good point, and we had a contractor report on the RPS program recently that Ryan Weiser and Kevin Porter had coauthored that raised those deliverability concerns with the existing structure of the program.

I think the draft ALJ's decision that is out now at the CPUC intended to structure the 2005 solicitation tries to address that. I think it could be strengthened quite a bit, and I know that there is legislation currently I think in the second House in both instances trying to address improving the deliverability of out of state resources.

I think in the early stages of the program one way or another, we have seemed to have structured a lot of road blocks in terms of bringing renewable resources to load centers, and I do think along the lines that our consultants pointed out, there are better ways of doing it.

Any audience comments or questions? Yes?

MR. KINOSIAN: Robert Kinosian again. Just one comment on the stranded cost risk and the potential hold up that is for utilities to enter in to new contracts or to build new projects. The problem there is a lot less than it was historically. When deregulation was first looked at in the mid-90's, the stranded costs were for roughly half the utilities resources of nuclear plants and qualifying facilities that cost well over 12 cents a KWh on average. Now the stranded costs that we are potentially looking at are for contracts of much lower magnitudes of MWs in the aggregate, and the price is on the order of six or seven cents a KWh. So, the magnitude of stranded cost risk here is nothing compared to what it was ten years ago.

When you balance that out against the utilities existing their own resources, the hydro plants, coal, and nuclear, which costs on the average of around three to four cents a KWh, they've got a lot of existing resources that offset even the potential for those stranded costs not to be able to be recovered.

The bottom line is I think this is an issue that if the parties sit down and discuss with some compromises, there should be something that can be dealt with without it being the hang up that prevents new facilities from being built.

PRESIDING MEMBER GEESMAN: What is your take on the role of debt equivalent as a disincentive to the utilities to enter in to long term contracts?

MR. KINOSIAN: That is something that has been addressed at the Public Utilities Commission. The last time they addressed it, I cannot remember the decision number, they have approved some debt equivalency financing for utilities regarding incremental contracts, so hopefully that should not in any way, shape, or form be a hold up because utilities are currently the PUC's program seems to be to reimburse them for any incremental costs due to incremental contracts.

PRESIDING MEMBER GEESMAN: Do you think that is a sustainable policy, I mean Kevin's ten year scenario? Is that a decision that once it is made by the CPUC doesn't get revisited by some future Commission?

MR. KINOSIAN: It will likely get revisited each time the utility asks for an additional increase in their rate of return to deal with an additional contract. Parties will look at whether or not that contract in particular poses additional risks and whether there needs to be a need for additional compensation. It is an issue that the Commission addresses cost of capital every year for these utilities, and it is one of many many issues.

Right now, all I can say is that the utilities have risen back to credit worthy status very quickly after being in bankruptcy or on the verge of bankruptcy, so the Commission's recent history has been, you know, to make sure that the utilities are credit worthy and to address their needs.

PRESIDING MEMBER GEESMAN: Yeah, but if I am a utility and I am attaching literal significance to the published S & P criteria, aren't I always going to prefer to sign a three-year contract compared to a ten-year contract?

MR. KINOSIAN: Not if for the ten-year contract you may be getting an incremental addition to your rate of return to deal with the risks of that contract compared to the three-year contract which is what the Commission's process currently allows for.

Once again, each individual case is going to be addressed by the Commission, so it is not that there is a blanket okay. Any contract, regardless of the cost of risks, you are getting "X" for.

PRESIDING MEMBER GEESMAN: Other questions, comments from the audience?

(No response.)

PRESIDING MEMBER GEESMAN: Okay, we are going to take a lunch break.

MS. GRIFFIN: Wait.

PRESIDING MEMBER GEESMAN: I'm sorry, Karen.

MS. GRIFFIN: The choreographer is back again. Remember that we wanted to have a strong Act 1 finish, and so the finish was Greg Blue from West Coast Power who is up next, and then we go to lunch.

MR. BLUE: I'm hungry, so I won't be long. Almost good afternoon, but not quite. Good morning. Greg Blue idealogue, not really. I am with Dynegy on behalf of West Coast Power, and first before I start, and I am going to try to be real brief, but I do want to respond to some of the panelists I heard this morning and some of the questions that I heard asked by the Commissioners.

First of all, I think Commissioner Geesman referenced FERC Commissioner Pat Woods exit interview where he gave the state a D- or D+, I'm not sure. His basic thrust was that we weren't moving fast enough.

West Coast Power and in particular started participating in this IEPR process in October of 2003 at the hearing we held down in El Sugundo. Both of you guys were there.

We started talking about some issues there that I am going to be talking about again today because they haven't been addressed yet, so we are still doing a lot of talking. Also in reference to -- I heard a lot of talk about merchant generation and merchant generators.

I can't speak for anybody else, but we are not a merchant generator any more, we are an independent power producer. We don't build power plants spec or take merchant risk any more. That was the prior Dynegy, the prior energy companies.

That terminology is a misnomer, we really need to get back to independent power producers because that is what we have. We don't have a merchant market anymore.

The reference to aging power plants --

PRESIDING MEMBER GEESMAN: Do you bid projects as turnkey or with purchase options by the customer?

MR. BLUE: There is a lot of confidentiality associated with bids as you know. So, I can't talk a lot about bids, but we do bid -- most of our bids, and I am including across the country are tolling type bids. I do not believe we bid anything with a purchase option at the end, but I'm not the commercial person, so I don't know.

There was some questions about whether -- we are going to file written comments on the specific questions at the appropriate time, and in fact, next week we are going to be filing also comments on the environmental performance report and our favorite report, the Once-Through Cooling Report. I was going to mention that a little bit later.

The issue of aging power plants and whether there are detriments to new generation, we don't think they are, No. 1 because we need all the plants we can get right now. We need all the new plants we can build, we need all the utility plants we can build, we need all the renewable we can build. We need it all right now. That is a fact.

The quickest way to get plants to retire is for people to quit giving them power contracts. Okay, we've retired Long Beach at the end of '04 because we didn't have a power contract. Our shareholders eat stranded cost, and we eliminate stranded cost pretty quickly, so we are not going to be staying around if we don't have a contract, so right now people keep offering us contracts whether it is the ISO, the utilities, or so forth for the existing plants. Until we have a sufficient amount of other generation or other option transmission, you are still going to be needing some of these existing plants.

Let's see, some of the things we are going to say today will sound real familiar to you folks up on the dias. While we have been promoting some of these policy recommendations through or at the joint energy agency meetings, this is our first opportunity to put them on the record for the 2005 IEPR, so some of these will look familiar, but I want to talk a little bit about some of them, but we are going to put them on the record because we think they are important. So, this is our opportunity.

I am basically going to be talking about generation resource issues, no big surprise there. You know, we really need to keep moving ahead. A lot of these things before I really get started, a lot of these things are being addressed, again, not being addressed fast enough in our opinion, and I am going to talk about some of that.

As California has already outlined in the Energy Action Plan, you know, some of these solutions out here are contained already, and we support all of this. We support all the demand reduction we can do. We support energy efficiency, we support transmission additions and upgrades. We support the increased amount of renewable resources.

We need to be doing as much of three as we can as feasibly possible, but in the meantime we are going to have to end up I think at the end of the day building more gas-fired generation. Going back to the Energy Action Plan itself, the forecast that was presented in the Energy Action Plan was something like on the order of 1,500 to

2,000 MWs a year, a year. We are not quite there yet.

Our policy recommendations. Resource adequacy requirements, we've heard a lot of talk about this, but really the most important piece of this is penalties for non-compliance. We've got to have penalties. That is the incentive, you know. Unfortunately, sometimes there is an incentive of a carrot, and sometimes there is a stick. I think we may have to have a stick here.

Our biggest concern here is the slippage of time as we see in the workshop report has been been delayed. We see now the orders are going to be delayed. We are concerned about the June 1, 2006 time frame being delayed and/or being some sort of a half attempt in the first year. So, we are really concerned about that. We are pushing hard in that process to keep moving forward on this.

We think that, for example, you need to determine the penalties have to be severe enough to where LSE's, and I am talking about all LSE's, are going to have to get out and procure. That is the only way you are going to get them to do that.

Tradeable capacity markets, where

capacity can be traded bilaterally or in a centralized market, and we think needs to be administered by the ISO. We heard a lot of talk about that this morning as well.

What we think about capacity markets, yes, I agree with I guess Mr. Woodruff who said capacity markets in and of themselves are not the solution. You need capacity markets almost as the residual, the last resort so to speak. You need both long term contracts, and you need a capacity market.

What is happening in the next issue of the LSE's must procure power plant capacity through long term power purchase agreements. Yes, the utilities are moving ahead with RFO's. Every RFO that the utilities have issued comes with strings and conditions attached and/or limitations on who can participate. That is a problem. I'm happy we are moving ahead with long-term contracts. We think, you know, if we want to talk about rates and costs, we think 15 or longer -- you know, 15-year terms are better than 10-year terms.

We have done some quick calculations. The difference between a 10-year contract and a

15-year contract as far as capacity payments is about 15 percent, so if you want to reduce annual rates, you know, it is an idea of just like a mortgage payment.

PRESIDING MEMBER GEESMAN: Yeah, but that assumes that you amortized the principle over the term of the debt?

MR. BLUE: No, it does not. It assumes recovery of 80 percent of the debt, and you recovered over 10 years, you recovered over 15 year, and bankers are willing to -- what the banks want to do is they want to see a contract -- this is what I am being told, I am not the finance expert. I am being told by my people in Houston that banks will lend based on if you can recover 80 percent of your debt and your operating costs, they are willing to take some risks for that last little piece assuming there will be a market out there.

Balance procurement rules are needed to insure level playing field between utility-owned assets and I use the word merchant assets, but I changed that before, so IPPS. Once again, this is some of the same old policies I have been talking about, but what we are talking about there is the independent evaluator being hired by the utility. We think that is a big problem.

The utilities are applying for in their general rate case to have a department that does project development, which gets recovered by rate payers which we don't get project development costs recovered by ratepayers, so we think that is an issue there.

Again, we heard reference to the FERC mandated must offer. It needs to be lifted. A lot of people are saying it. FERC unfortunately came out with an order last week that maybe they are thinking differently, so we have some work to do on that. The support of all state agencies on this issue I think is critical. Removing the uncertainty over core/non core market structure.

I'm just saying we've got to do something, either get in it or get out of it, but just right now this uncertainty is not good for the whole market. So, we need to figure out what we are going to do there.

The last, no presentation is complete for me without a word about repowering. We think that state support is needed to implement incentives for repowering because these aging plants will shut down eventually. What is important is the existing sites, where these are located. A lot of these are located in the heart of the load center, I mean right there, and will pass any deliverability screen that is put up there.

We think some of these sites are important. I'm only going to read one quick thing. I don't normally like to read, but I am going to read one quick section out of the December procurement order that Mr. Geesman referred to earlier. This is the December 16 order PUC Decision 0412048. This is for the benefit of all my utility friends in the room here.

To this end, we agree that modernization of old, inefficient and dirty plants should be among the IOU's first choices of resources. However, we are concerned that the least cost/best fit process would not allow a positive attribute of a brown filled site to be fully considered or fairly assessed.

We disagree with SDG & E's position that the RFP process should automatically incorporate the positive attributes of the brown fill sites.

It is generally good policy to consider brown fill site before developing green fill sites because of existing infrastructure, being close to load centers, and many other benefits. Therefore, we direct the IOU's to consider the use of brown fill sites first and take full advantage of their location before they consider new generation on green fill sites.

If IOU's decide not to use brown fill, then they must make a showing that justifies their decision, and we will be of course reminding the utilities of this as we go forward.

PRESIDING MEMBER GEESMAN: Yeah, but Greg, I've got the same question I had on this topic of you last year.

MR. BLUE: Sure.

PRESIDING MEMBER GEESMAN: What incentive? You just got that preachy bit of rhetoric from an official decision. What else do you want? Do you want a bid adder?

MR. BLUE: Fine. Are you offering it? I mean if you are offering it, I think in my opinion it is good public policy for California to maintain these existing sites the same way it is good public policy to encourage the increasing use of renewables, the same way it is good public policy for reducing greenhouse gas emissions. I think it is good public policy.

PRESIDING MEMBER GEESMAN: What is --

MR. BLUE: I don't have a specific recommendation exactly what it is.

PRESIDING MEMBER GEESMAN: What is wrong with SDG & E's perspective that many of those attributes, if not all of them, ought to be reflected in the price you bid.

MR. BLUE: Well, today we've seen nothing but exclusion by a lot of existing resources on some of these things.

PRESIDING MEMBER GEESMAN: That is a different subject.

MR. BLUE: Okay. It is all the same subject to me.

PRESIDING MEMBER GEESMAN: Okay.

MR. BLUE: None the less, it is an issue. Not all of these plants need to be repowered, only the ones that we feel are deemed critical by the ISO and for reliability, and even the aging power plant report that was issued last year identified some of these existing plants, and they said they are needed. No matter what, they are needed in the LA Basin, for example, these plants are needed for reliability of control, they have all of this SKIT, noma gram, and stuff like that. Some certain plants are specifically needed.

PRESIDING MEMBER GEESMAN: We permitted the one plant that has come before us in that basin, and at the time that we permitted it, I observed that you guys had taken an awfully long time to get it to the full commission for a decision and expressed the desire that the plant go to construction as quickly as possible.

MR. BLUE: Unfortunately, the Edison RFO that was recently completed or just issued the ten-year RFO, again, the limitation for '06 to '08 on line date, if you come on line after that, you are out of luck. El Sugundo is scheduled for '09 type of a time frame. So, again, I applaud the RFO --

PRESIDING MEMBER GEESMAN: The early bird gets the worm.

MR. BLUE: I guess so. I'm not here to debate that topic, but you know.

The last policy we have recommendation -- we are going to be giving you some comments on this next week, some more detailed comments, but do not adopt a restrictive staff recommendations contained in the Once-Through Cooling report until information is collected and evaluated in the 316 B process. We don't have to get into a big debate with everybody here on this topic, but it is an issue that I think could inhibit because you have asked what policies will hinder things. We think this is a hinderance potentially. We are going to be fully and complying with the 316 B and all the federal rules there.

We are in the process of collecting data already on this stuff, and so we are already moving ahead, and even the staff report said that understanding the magnitude of some of these impacts is difficult until we have standardized kind of studies, so we are just concerned about some of the recommendations that are there. We will give you some specific comments on that next week.

PRESIDING MEMBER GEESMAN: You know, the state clearly has an interest in pursuing appropriate implementation of the new EPA regs, and the governor's ocean council I think is likely to be the focal point of that. Do you think the

316 B process for all plants along the coast is really the most effective forum for addressing these concerns?

MR. BLUE: Unfortunately, I am not an expert enough to even attempt to give you an answer, and I am not give you an answer that I don't know, so unfortunately, I don't know that answer.

The next two slides I am going to put up actually I gave at the June 15 Joint Energy Action Meeting in San Francisco. What this is -- actually in that presentation, I attributed Joe Desmon to this actual chart here which was Joe Desmon called his report card on energy policies from California. In fact, it really came from the CEC report, the 2004 Update Report, and we really liked this kind of idea of putting up there where are we on some of these things.

So, this is some of the big policy goals that was up there, and Joe Desmon had called this his report card. This is prior to when he was sitting on the Commission.

We put this up there, and I am again going to introduce this into the record again. I think having one in the '05 IEPR is a good idea, having some sort of progress report. Again, some of you all have seen this, this is our own progress report that we put up based on our policy issues.

For all of the reasons that I've talked about earlier, you know, maybe that is a D- or a D+ there, I am not quite sure, but again, we think that this idea of tracking where we are on some of this stuff is important because, again, some of these things I've been talking about since '03, and we are still not there yet. So, with that, I will close and take any questions.

PRESIDING MEMBER GEESMAN: Thanks, Greg. Any additional questions or comments from the audience before we take out lunch break?

(No response.)

PRESIDING MEMBER GEESMAN: Okay, we will reconvene at 1:30.

(Whereupon, at 12:15 p.m. the workshop was adjourned, to reconvene at 1:30 p.m., this same day.)

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AFTERNOON SESSION

1:40 p.m.

MS. GRIFFIN: Thank you. Before we start this afternoon, for those of you who haven't checked the news, the count in London is up to 40 dead and 700 injured in the bomb blast.

This afternoon's panel, we are starting off with the three IOU's. You are all well organized at the table, so if we can just take you in order with San Diego going first, thank you.

MR. SAKARIAS: Good afternoon. I am Wayne Sakarias from San Diego Gas and Electric and also SoCal Gas. I very much appreciate the opportunity to speak today. More than that, we very much appreciate the serious effort that this agency and the PUC have been engaging in to cure the problems that we had in the energy crisis.

I worked as the Director of Fuel and Power Supply for SDG & E during the energy crisis, and it was an awful time. Every day our CEO would say it is going to get worse before it gets better, and he was right. So, we are very fortunate to have the people that we have in these two agencies. We really look at it as kind of a team effort, and we appreciate that a lot.

COMMISSIONER BOYD: How come your hair didn't turn white like mine did?

MR. SAKARIAS: Just fortunate, heredity. I'll give some examples. We talked about the Mission Miguel ceremony today. We also had a recent approval by the PUC of the Otay Transmission Project which will facilitate the Otay generation plant, and that is all to the good.

We do live in the shadow of the energy crisis, and our first actions need to be to make sure that we have cured all the problems of the crisis. We have made a lot of good progress, but the substance of what I want to talk about is what is left to do because we don't think that we've finished that job.

Our view of the policy issues is a bit different level than the policy issues in the discussion paper. It is a bit higher level than that. Those are the things that I will direct myself to. If you want to talk about other issues, I'm certainly prepared to respond to those questions if I can.

In our view, there are seven things that need to be done still by the state to get us to where we think we need to be, and that is to provide confidence in our citizens that they are going to receive reliable service at reasonable rates. That confidence was torn away from them during the energy crisis.

I just want to go through those seven points. The first one is we need to fix the ISO's operations. What I mean by that is one of the major causes of the energy crisis was a flawed market structure. Now my perspective of flawed is different than Jerry Jordan's was. They are on the right track, but they didn't do it right.

The ISO is in a process now and has been for a number of years of reforming, and we are not comfortable that we are there yet. The schedule has them completing this in another year or two. Will they complete it right, will they complete it on time? We don't know.

The first thing we need to do is make sure we get those flaws fixed. By the way, the first three of these points are points that we believe need to be in place before we can reopen any kind of customer choice.

We are a supporter of customer choice. We have been since its inception, but we believe that there is a sequence of events you need to take, and this is one of those three.

The second thing we need to do is what I've referred to as be sure there is enough supply. Some people refer to this as resource adequacy, insuring there is adequate reserves. The PUC is in a process to try and do that. We think the PUC is not quite on the right course.

The approach the PUC is following is load serving entities provide for resource adequacy for their own load. They do it less than a year in advance. They do it for the following summer. You might not know whether they did it or not until you've had a shortage. Then we will deal with them through penalties, unfortunately, we may also deal with it through outages.

We don't think that is quite the right approach. We think that you have to have an approach that applies to everyone. We are concerned that this approach does not. As you know, there are questions we heard today about jurisdictional authority of the regulators. That probably is going to need to be cleaned up with legislation. There is also some entities are just excluded from that process such as publicly owned utilities.

We think a process has to give timely signals to build infrastructure. I mentioned that the process that we have right now is you plan today, commit today for the following summer. Well, there is no signal for new infrastructure three or four years in advance or the amount of time it takes to plan, permit, and construct new supply.

So, we don't think that current structure accomplishes that. We think it needs to prevent free riding and cost shifting and cost stranding. What we are worried in a period of transient load where load goes from one supplier to another is who is planning for that load. We have two people planning for it or nobody planning for it.

That causes us a lot of concern. We are concerned that there are entities today that may be free riding off of this capacity utilities already have. We are very concerned that we get on the right track on this, and our approach favors a centralized process rather than a decentralized process where ISO or some other entity manages the resource adequacy and people can acquire the capacity themselves, but then supply it in through the ISO, or the ISO will acquire the capacity through a process where it is done several years in advance rather than several months in advance.

PRESIDING MEMBER GEESMAN: Do you think that is consistent with the cost pressures that are being brought to bear on the ISO?

MR. SAKARIAS: I'm not clear on the question.

PRESIDING MEMBER GEESMAN: I didn't phrase it very elegantly, but it would appear to me that there are fairly strongly presented positions by the muni's and others that have gained a certain level of traction with FERC about the costs of ISO operations and as a consequence, the role of the ISO recently seems to have been either static or shrinking. You are suggesting an expanded role for the ISO. My question is, do you see that being consistent with the arguments about ISO costs?

MR. SAKARIAS: What we have longed felt, and when I was in fuel and power I believe this way back in 1998, is that the ISO could do a better job in managing the costs of the services it provides. This certainly is an additional service, but it is a service for value. You get something out of it. It is something that you are going to wind up paying for one way or the other anyway. We were going to have some regulator somewhere trying to engage in oversight over a bunch of individual LSE's and possibly litigating their jurisdictional authority to do it in the first place. We are going to have some costs there.

My answer is, yes, it is an additional cost, but one for which we would expect value, and secondly, what we would rather do and see the ISO do is manage the costs for the services it provides in a more efficient manner. We are certainly hopeful that with the new leadership, that we will see that kind of thing.

The third thing that we think needs to be done and also one that we believe is essential before it can reopen customer choice is to get rid of some of the perverse price signals that are embedded in the rates and primarily the one I am thinking of is a cap on customer rates caused by AB 1X. What this does, in essence, is give customers an incentive to go someplace else rather than bear the cost of that subsidy that they are providing to the AB 1X group. It also gives price signals to use energy when you shouldn't be using it.

So, we have long supported that reform, that is a political difficulty, we understand that. We think there are ways to deal with the political issues, especially those wanting to make sure we are protecting those people who are disadvantaged financially. We don't think you should shut the door on that issue. If you don't take care of that issue, then when you reopen customer choice, you are just giving incentives for people to leave just by the basis of the cost, and someone else is going to have to bear those costs.

Beyond those, the other four things we think the state needs to do are independent of whether we have customer choice or not. The fourth one is to reform transmission siting, and we have had a lot of dialogue on this. We are very appreciative of people's attention to this issue.

There is cause for hope on this. We talked about a couple of lines that PUC has approved for us. They have obviously backed it up with action and then that is good news.

We do think there is still opportunities for regulatory overlap, regulatory duplication, iterative processes all which slow down the process and also for people to misuse the process as a means of slowing it down and hopefully stopping it. Those are things that need to be cleaned up if we are going to get transmission siting to work as efficiently as we can. Not to abandon environmental concerns, for example, or abandon issues of is this the best alternative, but let's do it the most efficient way we can.

Coordination -- I'm sorry.

PRESIDING MEMBER GEESMAN: I recognize the desire of probably all regulatees to say nice things about the regulators, and I do think that the PUC certainly deserves commendation on the recent Otay Transmission decision. That was a 15 month process, and I think by the standard of past performance, that is pretty good. That was a pretty easy line, and let's not kid ourselves that you are unlikely to get future projects as easy to approve as that one.

The Mission Miguel Project, which was of critical importance and identified as being of critical importance, some number of years ago when it first emerged out of the ISO planning process was allowed to age or season or perhaps simmer in somebody's desk drawer in the regulatory process for well over a year with no clear opposition to the project at the time. I think that we still have a legacy of poor performance in this area, and we ought to be held to a pretty high standard in terms of trying to improve it.

MR. SAKARIAS: You've described why we think this job still is not complete, and we are still feeling the effects of the Commission's failure to approve the Valley Rainbow Line. We think that was a big mistake, and one that has cost our customers. Different leadership, different circumstances, but events can change. We can have different leaders again, so the process needs to be reformed so we can correct --

PRESIDING MEMBER GEESMAN: The projects that you've got in front of you right now are among the tougher ones for the process to digest, and I think the challenges we are likely to face in the next several years in transmission will be substantially greater than we faced in the past several years.

MR. SAKARIAS: I think that is true. The two projects you mentioned are the low hanging fruit kind of things. It is these longer facilities going across lots of territories, some of it state owned, some of it privately owned that become big problems. In the long term, we really need some kind of planning process for corridors.

It is easy to over simplify that. That is a very difficult job, but it is one that in a state that grows as fast as this state does, we can't ignore it, we have to find a solution to it.

I think that there have been some very helpful dialogue on how to coordinate or coordinating with the ISO. The ISO does a lot of the work up front as we heard earlier today.

In the case of Valley Rainbow, all that work was ignored by the PUC, and we think we can do better than that, and so that is one of the areas that I think we would like to see reformed. We have some growing policy concerns. We have heard within the walls of not these offices but in the capitol people talking about disconnecting transmission and renewables. That we can build renewables and take advantage of them without transmission.

We just don't think that is true. It is true for some, but it is not true for a lot of the kinds of facilities that we think are going to need to be accessed. Wind is a very obvious example, and we have had some talk about that in context of Tehachapi's. San Diego also has access to wind resources that you can't get to them without new transmission over areas that might be viewed as sensitive.

I've read in our local media in San Diego several articles of people saying, oh, there are three wind areas identified for study in San Diego. We don't really like any of them. Well, that sort of narrows our opportunities quite a bit.

You are right, this is a tall job, and we are concerned because of that talk. Now that you can do renewables without doing transmission, and we just don't think that is true. If that is the direction we are going in this state, we are going to have a problem on renewable portfolio standards.

The fifth thing we think we need to make sure we have in place is -- the shorthand is competitively priced, diverse, and reliable generation portfolio. The long hand for that is to make sure we have a process that everybody is okay with for how we access new supply.

We think we are on that track in San Diego. We have gone through a bidding process that resulted in two new power plants being built in San Diego. What we don't want to wind up doing is having to litigate the process every time, and we don't want to have something that winds up being sort of a carbon copy of my old favorites, the BRPU, which I worked on for a number of years before I started doing this.

We envision a competitive process, we don't envision that the utility will build itself, but would engage in turnkey. We particularly are concerned about utility ownership of a substantial amount of supply in transmission constrained areas where there is RMR contracts so that we cannot be held up for ransom by other suppliers where there is not enough competition.

Those are the kinds of things that the process that we envision would have to undertake.

PRESIDING MEMBER GEESMAN: On the BRPU, Wayne, I think there is something about our regulatory process in California that naturally gravitates to the BRPU, and I would hold out as an example of that virus replicating itself once again.

The market price referent process that we utilize for the renewable portfolio standard. Everyone has the best of all possible intentions on this. There is not yet the evil witch from the south that appeared at the tail end of the BRPU process on the scene, but the natural tendency seems to be to make it more and more and more complex into a tribute levels of precision to the calculational process that most mathematicians would tell you defy logic.

So, I hold that out as an example. I don't know how to resist that.

MR. SAKARIAS: First off, I wish I had said that myself because I think you accurately stated a lot of the problems of the BRPU. We are not going to be able to avoid to press toward it. What I hope we can avoid is the feeling that people are excluded or unfairly treated unless we have such a process. I don't think it is necessary to have such a process.

We believe that we treated the bidders

fairly in the process that we went through, and of course, we have tried to use this public group as a means of kind of testing how are we doing, and so we are hopeful that we can work through that and get people to feel like they are not disenfranchised or unfairly treated, that they have a fair shake.

Our job is not really to provide fair shakes for people, our job is to provide good low priced energy opportunities, but fair shakes means you get people participating in the process, which you really need to have.

PRESIDING MEMBER GEESMAN: When you say this public group, do you mean the procurement review group?

MR. SAKARIAS: Yes.

PRESIDING MEMBER GEESMAN: What is your view as to how that particular institution works? I am not speaking as much about your own experience with your particular group, but how do you feel about that as an institution?

MR. SAKARIAS: Unfortunately, I can only give it based on our own experience, but let me say that when it was first identified by the PUC, I looked at it with a lot of skepticism. My people have spoken positively about it because it gives you that check from people who have an independent interest, it is not generators telling you how you ought to do things, or a utility telling you how to do things, it is people who have a more independent outlook, and that is helpful to us.

So, what I have heard from our people is positive on that. That is unfortunately all I have to go on other than it has reduced my skepticism a whole lot.

The sixth thing we want to do I think is facilitate the renewables target. We have had a lot of discussion on renewables today. It is obviously a clear goal of the state. It is our clear goal. The things we think you need to do is provide as many tools as you can to get there. We have talked about these before.

How do we take care of the transmission process? We think it would be helpful to have a system of tradeable credits like they have in Texas. I mentioned to you some of our cause for concern that people are saying you don't need either of those. We don't agree with that. We want every tool we can get because we are not in the middle of resource rich, renewable resource rich area in San Diego, so we need all the tools we can get to get where the state wants us to be.

PRESIDING MEMBER GEESMAN: Hopefully you get those for the 2005 solicitation.

MR. SAKARIAS: Yes, and we do have this option outstanding, and I am expecting that we are going to be starting to make announcements in the reasonably near future. That is going to start also revealing what is going to be needed and what is not going to be needed.

The last thing that I think we need is what I've got my notes here as stabilized rate competitiveness and meaningful price signals. What I mean by that is we can't have select burdens on some players that don't apply to other players.

In this state, we apply things to IOU's on a policy basis that we don't apply to publicly owned utilities, and yet at some level, there is competition among those entities for retail supply. Why do these policies apply inconsistently. Within that context, I think on a higher level, we need to think seriously about the cost of the policies we do apply.

One reason we don't want to apply them to muni's is we don't want to impose a cost on them. Somehow we seem to be okay imposing the cost on investor-owned utility customers. Their rates are high. I've got to tell you, our rates in San Diego are not low, and I went through the burden of when they were high back in the 1980's, and it is not where we want to be.

We looked at these programs, and we always ask, all right, do you want to pay for it. That's fine, but understand the cost that it is going to impose on customers already paying high rates.

Those are the things that we think need to be done at a high level in terms of getting us back to where we think we need to be in terms of confidence for our customers that they are going to reliably served and get what they expect and deserve to have.

I'll answer other questions either on these or any of the issues that were raised in the discussion paper.

PRESIDING MEMBER GEESMAN: Thank you, Wayne.

Stewart, you are up next.

MR. HEMPHILL: Thank you, Commissioner Geesman, and good afternoon to all of you commissioners. My name is Stu Hemphill, I am the Director of Resource Planning for Southern California Edison.

I want to thank you for raising a number of issues. I think that they are good ones to be asking. I just wish you had given us a little bit more time, but thanks to Karen Griffin for giving us a gold star for being the only ones to have answered those questions.

PRESIDING MEMBER GEESMAN: How else could we see you every week up here?

MR. HEMPHILL: There you go whether you like it or not. I don't want an answer to that one. I think it is an important role of state government to both raise these questions and also address them in the best way possible. I only have two issues for you today, and you have heard them both. So, what I will try and do is at least bring them up and connect them and see if that works.

I can talk about BRPU and PRG's and a bunch of other things if you so desire, but what I really want to focus on is on the retail market.

I believe the retail market is something that needs to be stabilized, and if we reach that in California, many of the other issues that you've raised will go away. They will follow suit. That includes the investment in new generation that includes what to do with expiring QF contracts and probably a host of other issues that you've raised.

The way it works in this market is that everything follows the retail, and if there is instability in the retail, there will be instability in the wholesale, and there are a lot of potential solutions for the retail markets.

Some have talked about core and un-core, and, yes, that could work. Others have talked about coming and going rules, and the question there is, you know, how can you get it to provide the right incentives so that you will have the investment in infrastructure and new generation that everybody in California needs.

A third would be to either freeze it or have it if you go, you are gone policy which is I think Kevin Woodruff mentioned is good in concept, and I agree with him, but very difficult in practice. As I mentioned last week, it is not something that customers desire. What they would really like is a free option to come and go as they please, and that doesn't work for any of the entities in California from a practical business standpoint.

It is a challenge, but I think it is the most critical thing that this State of California should be focusing on.

The second issue which you've also heard and it is related is fair and equal treatment retail obligations. Even if you have the coming and going rules and you have a stable retail market, if you continue to impose obligations on one entity and not on others, you will have continuing pressures to reopen and unstablize what otherwise would have been a stable retail market.

It is a reality, that is what we see her in California often, and so the simplest way to implement it is to assure that each has equal obligations.

There have been a lot of discussion today about generation, who is going to contract for generation, who is going to provide the investment opportunity. You know, a couple of points there, first, I've yet to see a single ESP go out with a long term RFO. Even if they are credit worthy, that is just a reality, but again, it is an equal obligation that if one entity is doing it, the other is too.

It is not about stranded costs as Bob Kinosian suggested, although that is an issue. It is about retail rates, and if one is going after three cent power and the other one because it is going after seven or eight cent power, there will be a continued upward pressure on rates that must be addressed in some way.

Stranded cost is an issue, but if you continue to put upward pressure on one entity and not another, you will create a domino effect which allow more to shift from one entity to another, which then if stranded costs are recovered causes the rates to rise again, so it just perpetuates itself. That is why those two are the most critical issues.

That is all I have.

PRESIDING MEMBER GEESMAN: Tell me, Stuart, realistically from your perspective, how could you achieve those two objectives in any way other than simply freezing the current system creating a Berlin Wall between your customers and the escape route and basically dividing up the market as it currently stands today?

MR. HEMPHILL: A core and non-core with the appropriate coming and going rules is possible. I am not saying you will find it anywhere across the country now, but I think there are just a few key elements and probably a lot of fighting between what the right approach is. You know, what is the right level, how long is the notice period, what are the consequences of coming back. If all of those issues, and we spend a lot of time in California trying to work them, I still don't think we are there yet if what we are trying to do is encourage new generation investment, but those are the critical issues that we should be focusing on.

PRESIDING MEMBER GEESMAN: What in your judgement other than political aspects has kept us from embracing that core/non-core model?

MR. HEMPHILL: I think it is a game of chicken. I think it is if nobody wants to be the one who is going after the investment because whoever does is disadvantaged to those who don't. That is the political consequences of being where we are.

I am not saying we would necessarily find that at the end of the day we would find an acceptable solution to all of the issues, but that is where California needs to lead.

PRESIDING MEMBER GEESMAN: Yeah. The regulatory agencies have made motions in that direction. I don't think we've gotten much traction with the legislature, but it doesn't mean we shouldn't keep trying.

MR. HEMPHILL: Still core and non-core has not happened yet, it seems to be something that pops us now and again, it is just the fact that it pops up does continue the uncertainty in the retail sector.

PRESIDING MEMBER GEESMAN: Okay, thanks very much.

Hal.

MR. LA FLASH: Good afternoon, Commissioners, my name is Hal La Flash, I do resource planning at PG&E. I talked to Stu last week and said, well, this is fun, we've got to do this again sometime, but you guys really didn't need to take us up quite that soon.

I don't have that much new to add. We've heard a lot of things from this morning's panel and this panel that I haven't heard a lot of disagreement, I've heard some fine tuning about certain ways that it would be enforced, but the issue about resource adequacy, for example.

In fact, I think if you look at one of the lead off questions was the 8,000 MWs. There are 4,000 MWs actually are in construction, so I think we have to look at those and give credit too. Now that the Calpine projects are on line, I think all of the remaining 4,000 MWs are all utility sponsored, either owned or contracted. That gets to those resource adequacy problem, that it has got to be applied uniformly to everybody. I think it has been mentioned several times, one year at a time isn't going to work. You are not going to get new steel in the ground on a one year commitment, so it is going to take some type of multi year commitment to do that.

The point that you asked Stu about why is it the way it is in the retail market now, everybody wants to be a free rider, and it is just human nature. If they can get a deal and not have to pay for it, they take that deal. At some point, everybody has to be responsible for this. It applies especially to the number we heard this morning, 13 percent direct access. 15 to 17 percent reserve margin is fine if everybody follows it. If it is only applied to the other 86 percent of it, it is not going to get you there.

As for that reserve margin, the question was asked, does that accommodate one in ten, one in two (indiscernible). It is meant to accommodate hot weather conditions to the level it is, and it will accommodate forced outages as long as it is applied uniformly to everybody. One of the other questions was about least cost/best fit.

Wayne already used my line about BRPU, but to me, if you make least cost/best fit any more formulaic, you risk making it into a BRPU. I think least cost/best fit works best if the utilities are allowed to use it to meet their portfolio needs.

The question came up about the old plants and whether there are keeping the new plants from coming in. I think there is a big difference between the capabilities and the costs of the old plants versus the new plants. I think the discussion this morning about the 20 percent operating factor on the old plants, you are not going to see a modern full cost combined cycle operating at that level and surviving.

There is a role for the old plants, and the old plants are especially needed given the uncertainty of the retail market. They are an option right now, and until that retail market is settled, that is not an option people are going to pursue rather than put out a lot of money for a long term commitment on a brand new asset. You can do some life extensions for much less on these assets.

PRESIDING MEMBER GEESMAN: Yeah, but they are currently being propped up in your service territory by RMR contracts. Take away the RMR contracts, and a lot of those plants retire tomorrow.

MR. LA FLASH: There is an issue around that. In fact, the plant that we just filed to site is in an area that will probably relieve some RMR contracts, but it will be a new plant, so there is at some point in time new plants will replace some of the old plants as they come in. Somehow you have to keep the option out there. Maybe those old plants that have taken off of RMR pop right back for resource adequacy capacity because they are going to be a cheap way of providing that.

PRESIDING MEMBER GEESMAN: That might be at a little more market related pricing than the RMR contract allows for.

MR. LA FLASH: It would definitely be a different price than the RMR is. We are doing that now on the (discernible) deal that we have on the Contra Costa and Pittsburgh units that we are getting capacity value out of what is basically a RMR contract.

There was a question about portfolio diversity and should we be limiting the amount of gas fired generation in our portfolio. I think the portfolio is pretty well prescribed now in the loading order. The loading order is a good thing, and we believe in it, but you really need to have the ability to run those gas plants to balance that loading order as you are bringing in renewables, especially intermittent renewables and as you are changing your customer's load profile with energy efficiency, you have to have the plants that are out there that are available to respond to that, and those are gas plants.

I was glad to hear a couple of parties

brought up the fact that rates need to be thought about too because in all the questions as I was going through them, I didn't see anything in there where anybody was really asking about rate impacts. That has to be an important consideration too.

PRESIDING MEMBER GEESMAN: We rely on our sister agency to rivet our attention on that, but it is a good thing to point out because it isn't one of the things that we traditionally put at the top of our list of considerations. Ultimately, it is one of the required litmus tests, but we are not a rate setting agency, so it is nothing that we prioritize, but I think you make a good point there.

What do you think of Wayne's suggestion, which I believe San Diego has made for several years now that the ISO be given the task of providing reliability services and using that approach to avoid some of the free riding that certain parties would like to engage in?

MR. LA FLASH: I don't know that we are completely on board with the ISO doing it yet. We do appreciate the need that somebody has to do it. In fact, I'm surprised Stu didn't mention Edison's filing, which I think we filed in support of.

We think that there probably needs to be an ability for a party to opt out, to show that they have provided their own resource adequacy, but you need some type of back stop mechanism, if not the ISO or the utilities, somebody that can provide that.

PRESIDING MEMBER GEESMAN: When you speak of Stuart's filing, you mean the structure of their RFO?

MR. LA FLASH: I think that is what he is talking about. I mean, the question that is often raised a lot of times being in a utility, people want us to do things always.

We are in a situation now where we have 115 percent of our own resources for 2005, and yet the resource adequacy requirements aren't until 2006. We also recognize that people in this state are concerned over supply reliability in Southern California, and what we did was structure and RFO for new generation so we would have new steel in the ground. The question is for whom is this being done. The answer is, well, this is the Southern California issue that we are attempting to solve, and so we went out for an RFO with a structure where all in Southern California would also pay for it, so I think that is what he was talking about.

PRESIDING MEMBER GEESMAN: Contractually, how does that work?

MR. LA FLASH: Contractually, we are the counter party. Does that answer your question?

PRESIDING MEMBER GEESMAN: Not entirely. Let's say I am an ESP within your service territory, and I've been free riding. In fact, my entire business strategy is based around continuing to free ride, how are you going to tag me for my proportionate share of that resource adequacy?

MR. LA FLASH: What we have looked for is a FERC tariff that would apply to the wires because this is really a reliability issue that we are dealing with, so it is part of the FERC reliability tariffs, and that would apply to everybody who takes service from the transmission system.

That is the whole point of the cost recovery mechanism that we proposed.

PRESIDING MEMBER GEESMAN: Okay.

MR. SAKARIAS: Commissioner, just let me

make it sort of clear I think. It is probably clear already. If we acquire the resources we need for our customers, we don't want somebody else billing us for additional resources. Our customers are already paying enough, so if something like that went forward, they would have to find somebody who is going to be paying for it, but it is not going to be our customers.

MR. HEMPHILL: We are in exactly the same situation. We have also procured sufficiently for ours, but we are trying to step up and make sure that people are comfortable with the level of generating resources in Southern California.

PRESIDING MEMBER GEESMAN: My recollection is that your RFO is ostensibly on behalf of all of the SP 15 region?

MR. HEMPHILL: Yes, that's the zone where both CAL ISO and the CEC itself has said are potentially short it.

PRESIDING MEMBER GEESMAN: How do you deal with the situation where San Diego, for example, may feel that they are already more than adequately resourced?

MR. HEMPHILL: And so is SCE. What we

have done is we have put it in front of the Public Utilities Commissions, and they are certainly going to hear from everybody as to whether they think it is appropriate or not. If the PUC chooses for us to not go forward, we won't. Again, we are just trying to assure that there are sufficient resources in the SP 15 area.

We would be perfectly happy if San Diego wanted to do this.

PRESIDING MEMBER GEESMAN: I think their view is they've covered their own obligation. They don't need your help.

MR. HEMPHILL: Exactly, and we are in the same situation.

MR. SAKARIAS: We appreciate what they are saying, but that is why we have proposed a way of dealing with resource adequacy without seeing if we can't bill all the other people who are already resource adequate for the costs that others should be responsible for. It helps to evidence some of the flaws in the current PUC resource adequacy approach.

MR. HEMPHILL: I don't disagree with anything Wayne is saying.

PRESIDING MEMBER GEESMAN: It makes a

good point. I am not certain that it makes a contract. Do you actually think real contracts are going to come from this process?

MR. HEMPHILL: We've certainly received quite a response. It is possible, it is conceivable. The question is, if not us, who or how is new generation going to be developed. If we can come up with another solution, let's do that one.

PRESIDING MEMBER GEESMAN: How do you think that structure fits your service territory?

MR. HEMPHILL: I'm not sure I understand.

MR. LA FLASH: He is asking me.

MR. HEMPHILL: Oh, I'm sorry.

PRESIDING MEMBER GEESMAN: I'm asking Hal, and you've got a lot of muni's that I'm sure would want to be heard from on the question.

MR. LA FLASH: I don't know that the muni's are our biggest concern, although some of the growing muni's might be another issue, but some of the historic muni's tend to look after their own. The new ones are another issue.

The issue I think is really more around the direct access customers that like the fact that they can get cheaper power now because they don't have to go out there and make long term commitments.

Fortunately, we are a little bit better resource than Southern California is right now. We've got a couple of more years to get it worked out for us. It just highlights that the issue is resource adequacy, and you are hearing different ways to try to resolve the issue, but I don't think that where we are going right now on the one year resource adequacy is going to get you there because it is not going to get any plants built.

PRESIDING MEMBER GEESMAN: How do you see the resource adequacy process being used on a multi-year basis. I mean, do you think that the requirement will ever be framed as anything other than a relatively short term requirement?

MR. LA FLASH: If you can require the entity to prove that they have a one-year contract, you should be able to require they can prove they have a three year contract or whatever the number of years is.

PRESIDING MEMBER GEESMAN: Take me to the time horizon necessary to incent new investment.

MR. LA FLASH: You need at least four years for a new investment. In our resource adequacy plans, we've talked about a five year commitment, but we've got others, TURN and others, and they talked about a three year commitment, but the point is it has to be multi years because you do need nominally four years to get a new investment on line.

Those that are out there now that are in the inventory can probably come faster because they've got a lot of the permitting done or all their permitting done. Generally speaking, you need four years.

PRESIDING MEMBER GEESMAN: Do you think the ESP business model is built around commitments of that duration?

MR. LA FLASH: Not at present, no. I have observed that is one of the things we thought about why we wanted a centralized approach because we realize there's transients going to be in the retail suppliers, and it makes it a whole lot easier for the comings and goings, you don't have to worry about making a five or ten year commitment when you really don't know how long you are going to hold that customer.

PRESIDING MEMBER GEESMAN: You know, I think even today, I think there is still a fair amount of political significance attached to that transient quality. I mean that is not quite akin to a constitutional right of privacy, but it is regarded as a valued aspect of the market. I think there is still political support for that. I know the regulatory agencies attach quite a bit of significance to it. I think for the most part, the legislature attaches a high significance as well.

MR. LA FLASH: I think we have had a record for a number of years as being in favor of customer choice, but we just want it to be a responsible choice.

PRESIDING MEMBER GEESMAN: Yeah.

MR. HEMPHILL: In a number of other deregulated industries what small companies have done is found that they can aggregate a service, and we saw this in airline and some of the other ones, warehouses, etc. There may be an opportunity for aggregation on behalf of ESP's to make sure that they are resource adequate as a way of minimizing costs and still allowing the transient capabilities you were describing.

PRESIDING MEMBER GEESMAN: Other questions for this panel? Any comments or questions from the audience?

(No response.)

PRESIDING MEMBER GEESMAN: I guess you guys must have resolved everything to people's satisfaction. Thank you very much.

MS. GRIFFIN: Panel 4. Having been at the Music Circus last night, not only was I reminded about the importance of a strong first act finish, it is really important to finish strong, so we brought in for our final panel some of the people who are really on the cutting edge of what happens when you have hybrid market that has been through some difficult times and is trying to get itself restructured and have some effective business models. We will take it away with this group, and if we could just go in the order that you are listed on the agenda, that would be great.

PRESIDING MEMBER GEESMAN: That makes you first, Katie.

MS. KAPLAN: (Inaudible.) There is a couple of issues we would like to touch on today, specifically things that we think the Energy

Commission can do to help meet the goals and the policies that have been set forth in the Joint Agency Plan as well as just in market design on a going forward basis.

The first thing is forecasting, and while the Energy Commission has historically done forecasting and has obviously engaged in the IEPR which will feed directly into the procurement policies of the Public Utilities Commission, it is critical that when we are looking at forecasting that we are looking at the realities of the real time operations of the grid, and then trying to back out long term forecasting from there.

Specifically, we've had concerns previously that some of the longer term forecasts have been a little bit idealistic as far as including specific numbers regarding demand response and some of the other goals, laudable goals that the state has imposed.

What we would specifically suggest is that there is a MOU or something like that entered into by the Energy Commission as the lead agency, but including the independent system operator when formally including a role for the independent system operator when specifically looking at forecasting.

We are afraid that some forecasts come out of the Energy Commission, they don't receive some kind of reality check as far as real time is concerned on a month ahead basis when utilities go to make their showing or all the (indiscernible) go to make their showing. We get concerned that if there is not like a "gut check" if you will, is this really right, so in measuring deliverability and all of that kind of thing that we could have problems. We would encourage there to be some kind of a MOU, again, with the Energy Commission as the lead agency, but just really a formalized role for the ISO in forecasting and feeding that into the PUC process.

PRESIDING MEMBER GEESMAN: I think that is a good idea. I will say in my judgement, we had a real hard time adapting what are pretty old and arguably antiquated tools in our forecasting process to meet more modern needs of our current market structure and better integrating the ISO into that process and better altering our tools to better meet the needs of the ISO is a high priority.

Commissioner Boyd and I both attempted

to articulate that a year and a half ago when we started this particular cycle for a variety of reasons, most of which seem inexplicable to me to this day. We've not made more progress on it. I think we need to geographically disaggregate our forecast which the ISO has requested that we do. I think we need to try and get on the same page with respect to the methodologies that each of us use.

I think we also need to distinguish between the end use engineering model that this Commission places great reliance on and which is best calibrated to a ten year time horizon. The shorter term forecasts which the utilities utilize largely for revenue forecasting purposes. It is not clear to me exactly what the ISO uses as a short term methodology, but I think we need to distinguish that if they are each hammers, they are hammers of different dimensions and intended for different uses. We tend to blend those and blur their distinctions. As a consequence, I think there is a high temptation to either misuse it or misinterpret them.

I don't know if you were at our demand forecast hearing over at CAL EPA last week, but this discussion of which conservation programs to include in the ten year forecast came up. Interestingly, our staff and the utilities appeared to be on different ends of the spectrum. With our stall being inclined not to include energy efficiency programs that had no already been approved by the CPUC, and the utilities being of the view that because of the loading order and because of the emphasis which state policy places on efficiency programs, they ought to be included throughout the forecast period.

So, the issue you raise is in front of us, and it is one that we will address in our report this fall.

MS. KAPLAN: It is very important that we are doing a look back as well, meaning that if the forecast is off significantly and utilities are procuring based on that forecast, we are the ones, our members are the ones that are caught in the middle because if utilities are procuring to an Energy Commission forecast and it is not right, and the ISO is saying that there is a different number or they are looking for a different set or types of units, then we are caught in the middle.

Ultimately, we are responsible to the

ISO for keeping the lights on. Nobody looks back to say, oh well, who cares if the forecast was right or not. Everyone cares if their lights stay on.

We think a MOU-type of approach where they have a formalized role in everything from a -- the Energy Commission should have a more formalized role in some of the month ahead or day ahead forecasting that the ISO has. One common methodology that if it is Commissioner Geesman or President Peevey, whoever, can pick up the phone and say, okay, that's what the forecast is, and everyone agrees on it. It does no good to have three or four different forecasts.

The second thing I wanted to touch on is regarding the 15 to 17 percent reserve margin. While that number has been adopted and we've been working actively within the resource adequacy paradigm as well as within the IEPR process, to answer the questions directly about is it enough. Well, it depends on what you allow to count to meet that 15 to 17 percent requirement.

If you let a bunch of non-deliverable contracts count to meet that requirement as the PUC is considering, and you rely on a must offer obligation that provides you 3,000 MWs plus in Southern California from here to 2008 or beyond, then, no, it is probably not enough because inherently you are procuring more by allowing these non-deliverable contracts to count.

PRESIDING MEMBER GEESMAN: Now the ISO issued a report here a couple of months ago that suggested that at least for now all in-state resources could be considered to be deliverable. Do you have a bone to pick with that conclusion?

MS. KAPLAN: We definitely do. Here's the thing. Is it physically deliverable which I think they've been really careful to say. They may be electrically deliverable. They don't have contracts. There is over 6,000 MWs that don't have any contracts, any financial obligation, so guess what? They are deliverable to Arizona, they are deliverable to Nevada, they are deliverable to LADWP, they are deliverable all over the place. You know, they are not just deliverable to meet the requirements in the ISO's footprints. As long as we allow folks to say, oh yeah, we are 15 to 17 percent resource adequate, but we are going to be utilizing these resources that are undeliverable, then it is not enough to keep the lights on.

I would suggest that if folks do say they are 15 to 17 percent resource adequate, then they don't need RMR, and they don't need the must offer obligation, and the ISO shouldn't be in any kind of a procurement role. So, you can't have both.

PRESIDING MEMBER GEESMAN: Do you think a liquidated damages contract is deliverable?

MS. KAPLAN: No.

PRESIDING MEMBER GEESMAN: What would you do with those going forward?

MS. KAPLAN: I think on a going forward basis, there needs to be a firm statement that they will not count to meet a resource adequacy requirement.

PRESIDING MEMBER GEESMAN: That is a pretty wrenching change, isn't it?

MS. KAPLAN: To the extent that -- basically, what you will have to do as regulators is say to the extent these contracts will count because they were entered into prior to people knowing what the rules of the road were, etc. I mean that is probably a reasonable direction to go, but you also have to recognize that there has to be a back stop role in there. If you allow LD contracts to count, you've got to have some kind of a capacity back stop to allow the units that don't have resource adequacy contracts to be compensated for the reliability services they provide.

Our position is that no new LD contracts should count under any circumstances to meet a capacity requirement. They are energy contracts, they are important, they have an important role in the market for energy hedging, but they aren't capacity. They don't get new plants built. If we are really trying to make the state resource adequate, you can't let them count.

PRESIDING MEMBER GEESMAN: What would you do with the old contracts, cold turkey or transition, or --

MS. KAPLAN: I think there are two ways you can go. It is not politically feasible to go cold turkey, right, but you do have to recognize that if you do allow them to count, then you have to have a back stop role. You have to have some kind of back stop contract, IEP's proposed day, reliability tariff type of approach that the ISO would utilize which would take the ISO out of the contracting role, and it would just be a tariff rate if they call a must offer unit. So, it eliminates the RMR type of continuing to rely on the RMR. It would be a tariff component that would just transition until you get the local requirements that are implemented.

Those are all things that they have to merge together. This whole notion that you can count LD's to meet this 15 percent requirement and not have any kind of back stop and still rely on 6,000 MWs in Southern California that don't have any kind of compensation is ludicrous, and it won't keep the lights on.

If policy makers decide to take that direction, they have to also recognize that you have to compensate existing resources and new resources for the reliability service they are providing.

Lastly, I think, you know, when you talk about the 8,000 MW that are permitted that have not been built, one of the things that we would suggest, and you've probably heard this before, is a consideration of not allowing the permits to specifically expire, to have a hearing at the end of -- if a permit were to expire, to have a hearing or set up a procedure where you would have a hearing to determine whether or not the permit should expire or not.

If there is new information that comes to light, perhaps you require them to go through part of the permitting process again or something like that, but they shouldn't just expire out right, and perhaps that would be one way to allow more plants to be built once market conditions sort of stabilize.

That is the last thing, and I look forward to your questions. Thanks.

PRESIDING MEMBER GEESMAN: Thank you. Bob.

MR. ANDERSON: Good afternoon, my name is Bob Anderson. I work for APS Energy Services. We are ESP, and I can clearly talk about our business model whenever anybody wants to do that.

I'll start by just describing who we are because we don't normally get a lot of press. We are the only last standing ESP that was here on April 1, 1998 that hasn't either been sold twice or changed their management and their name.

So, in these discussions about what works, what doesn't, responsibilities, things like that, we do have some things to say.

As far as me personally, my position in the company is I am responsible for all 20 business processes it takes to sign customers up, serve them, manage the risk around them, build them, settle with the ISO, and handle any kind of contractual issues, both wholesale and retail.

We've been doing this now -- I've personally been doing this for eight years. I've seen the energy crisis, I've seen both sides, the generation side, the LSE side, what happens when there are distortions in risk management that causes major shifts in the market. We have a lot of experience that way.

Today what I wanted to talk about briefly before I respond to some of the Panel 3 comments, our perspective right now is that California is trying to solve a three simultaneous equations at once. One representing production, one representing delivery, and one representing customer usage.

We are not doing a very good job of the integrated nature of looking at the variables in each of these equations. We are doing a lot of work in discreet areas, renewables, resource adequacy, things like this, but nobody is actually trying to find a solution for all three equations, and we do believe that there is one out there.

One of the first things we would like to suggest that would be a solution is an ability to draw back from the peak load situation and hoping that new generation will be built to meet the peaking elements of your load across the year. There has got to be a way to be able to reduce and peak shape that, and we believe that 2000/2001 taught us some very significant lessons, one of them was that the residential customers are absolutely part of the solution.

The 20/20 program had huge success, probably one of the best things that happened to us.

PRESIDING MEMBER GEESMAN: It wasn't peak oriented.

MR. ANDERSON: You can argue that it is not tied directly to critical peak, but the residential load shape absolutely affects us during the on-peak and the critical peak hours. We can get into a discussion about whether or not it can be gained by residential customers for that program, but I am sure that would be another discussion.

The combination solution that we are talking about is getting farther into and on the edge of the comfort zone from the regulatory process in making aggressive entries into the 20/20 program. In fact, going so far as to attempt something that might be on the order of a 40/20 program.

Now where we are coming from with some of these solutions is a simple fact that when you look at the price signals from the load, you have customers that were shown a bid to reduce their load in the 2003 demand response program at the ISO that had 20,000 MW month option payments and $500 MWh energy payments.

We had one customer that joined that. It was the very first customer that joined it with the ISO. Customers were not biting on that. On the other side of the coin, you have customers on a punitive perspective that we've shown thoughts of going to a critical peak pricing situation where we are tag them for $250, $500, or $1,000 a MWh. In our residential rates, we have base line ratchets that go anywhere from $200 to $260 depending on where you are, 100 to 130, and between 130 to 200 percent as you go forward.

Clearly to us, the commercial and industrial customers, their offer to reduce is not at the price that people are willing to pay. In fact, it is probably at twice what the current wholesale price cap is at. That is a completely distorted view.

On the residential side, I don't believe we've done enough to pay for their opportunity, and I think we get great success again like we did in 2000. If we were to achieve that, one thing that happens immediately is you do peak shave, you take yourself away from the brink, and you can connect that directly to lifting the price cap.

You can tie it to $100 increments and say that if I get 4 percent reduction a load the summer of 2005 from a beefed up 20/20 program, as we go through the fall, we are going to go through an advice letter process, and we will create a way to lift that price cap and give generation a signal because we are not feeling like we have no say in this. Load is actually coming to the table.

That part of the solution can be visited again when we get to local area reliability.

PRESIDING MEMBER GEESMAN: Do you need

advanced metering technology?

MR. ANDERSON: No, no. The 20/20 program -- the beauty of one of the things from the 2000/2001 program that will lead us to the local area reliability discussion is the outage areas.

The work that was done to map the outage areas, the rotating outage areas across the UDC's can easily be used to give us a geographical demand response program, and we could easily change the price signals dependent on where you have local area reliability problems, so there is a very real tool here.

The third component of this getting to the delivery phase, we absolutely believe that some of these new transmission projects that have been approved recently, and the ones to come, we need to aggressively push on the transmission engineers and look at new technology. The new composite power lines that are produced by 3M and a few other companies, they've already been tested by the Oakridge Labs for four years in multiple areas. They are in place in WAPA's territory and EXCEL's territory. We need to push harder on that.

It is amazing to us. We think it is revolutionary that you can have transmission that have 300 percent capacity compared with what we have today and the metallurgic issues. You are changing from pure aluminum wraps around a steel cable to aluminum zirconium which we all know the metallurgy around that with our nuclear power plants.

You wrap that around a fiber, ceramic fiber, that should be looked at more aggressively. If we did those three things when we get back to the local area of reliability discussion, we are armed now with a couple of different things beyond just this notion of going and getting 15 to 17 percent for one year. I absolutely agree that resource adequacy has to be dealt with. We believe the core and non-core market will work very affectively in California.

I am at a loss to understand why people don't see the core and un-core in gas in the same light that they do potentially electricity. If we go down this road, resource adequacy clearly does have to be dealt with.

The 15 to 17 percent for one year does not give a signal to new generation. What it can do is do the same thing that RMR does, and that is make sure the generation we have right now stay here, that they are still in there. That is vital for us to do too.

From a load serving entity perspective, there isn't -- I am really getting weary of these insinuations that energy service providers don't understand reliability and that they are trying to shirk their responsibilities. As a matter of fact, the only LSE I'm aware of that has gotten a direct communication from the CAL ISO when it comes to deliverability and resource adequacy was certainly not an ESP.

This issue, we can work on this together. I think the time has come for that, these issues about core and non-core, about generators versus LSE's, we need to get beyond this. This solution takes everybody -- there is a solution to these simultaneous equations. It is lifting the price cap. It is understanding that we need the units that we have today.

It is not going to serve our purposes, a load serving entity to know that the generation people are getting weaker by the year.

I can't deal with non-credit worthy

counter parties. When we get into that whole discussion about liquidated damage contracts, buying unit contingent transmission contingent contracts from a non-credit worthy counter party is not what my risk management processes would allow. That is, again, I am not going to get into that discussion right now.

There is just an immense opportunity here. There is a lot of baggage, I understand that. The RMR contracts, everybody has their own view. The ISO would tell you they are terribly expensive. The generators would say, you know what, we've been ripped off so many times that we are just not interested in getting involved in this. We've got to get beyond that.

As far as ESP's and the business model --

PRESIDING MEMBER GEESMAN: Let me say on the RMR's, it is my impression that the ISO, the CPUC, and FERC have all been quite vehement about their desire to move away from the RMR contracts.

MR. ANDERSON: If we want to move away from the RMR contracts and create something different, that is a great segue back into the centralized discussion that San Diego Gas and

Electric brought up briefly. I am in total agreement with that too.

The point that the representative from Southern California Edison made about fair and equal treatment when it comes to things. My opinion fair and equal is they don't work together when it comes to ESP's and large LSE's. Fair is not necessarily equally loading down in a situation where the other counter party has no ability to sign ten year deals. However, the ISO would facilitate the middle ground in that situation.

Your question about whether or not the ISO can really handle something like this given the current situation in budgets and other things, I would just say that the seven years of operating history that we have and pricing transparency from the operating reserves market at the ISO has been excellent for us for two different reasons.

One, handling my portfolio, understanding relationships between ancillary service costs and this area versus let's say FERC cost based tariff rates, which by the way always are higher than what we have seen at the ISO.

The additional work for the ISO to

procure let's say another 8 percent reserves to meet this planning reserves and do it in two to three to four year terms is absolutely within their realm.

PRESIDING MEMBER GEESMAN: Yeah, I looked at the experience a year ago, fourteen months ago I guess is when it started between the ISO and that LSE down in Rosemeade that I think you were referring to on deliverability questions.

MR. ANDERSON: I never said that.

PRESIDING MEMBER GEESMAN: I thought I smelled that. On deliverability questions, and I saw the ISO shed what I regard as a fairly critical responsibility and attempt with the CPUC's encouragement to put that responsibility on the LSE's shoulders. I think that is probably a demonstrably inferior solution.

In our report last year pointed out that there were some real questions as to how workable that would prove to be. I don't think it has proven to be particularly workable thus far, but the important take away I gain from that was the ISO was in a service shedding mode or a responsibility shedding mode and not looking for new tasks to take on.

MR. ANDERSON: I would completely agree with that. I would say that they have been under achieving for quite some time. We have high expectations of what they can really do if given the task. I think a distraction that I am quite frankly at a loss to understand is given what you've just said why on earth would we be spending man hours to create a day ahead market in a situation where we are talking about 15 to 17 percent planning reserves where we already review the 2004 DMA report that says they've been decking things for a year.

Who is it that is going to be in this marketplace? I am at a loss to that with the exception of saying I would like to work for BPA Nevada Power and any surrounding area with the ISO if we put this in place because that is absolutely going to be what it is.

Reassigning some tasks and things like that I think would be very timely right now.

PRESIDING MEMBER GEESMAN: I think as the gentleman sitting next to you would tell you probably in private, there is probably some remorse over our having killed a perfectly workable day ahead market several years ago. It is a long memory that has produced the desire, I think particular on FERC's part to develop a day ahead market again that is perceived by many as a necessary element for a successfully functioning market going forward.

MR. ANDERSON: The day ahead market -- I traded the day ahead market in 1993 back in the time when if I tried to bring something from BPA down to Arizona and went to buy transmission, it was conveniently priced a quarter higher than what it was going to cost me to buy it from the person in between.

Ever since then, we have had a day ahead market. Now is it transparent like the California Power Exchange market? No. Can you look at Dow Jones Index as things like this and find the activity? Yes, you can. The idea where we are heading with local area reliability and with resource adequacy where we are talking about bi-lateral deals between counter parties, the transparency is completely lost on those, which is to us when I came this morning -- I flew in this morning on a plane. The four things that I was going to suggest that we as energy service providers desperately need from the wholesale market, we need transparency. That is the first thing that we need, and that is the one thing in the operating reserve market, the CAL ISO does an excellent job at.

We applaud all of the factors when it comes to transparency at the ISO. The second thing and very close is liquidity. We need the liquidity, we need credit worthy counterparts. The other thing I need in the wholesale market to actively work as an area service provider is product variety. I need ability for someone like Goldman Sachs, Morgan Stanley, others to make a market for options, daily options, monthly options, things like this.

If we go to the realm of locking up four year deals to prove resource adequacy, I can't even imagine managing a portfolio where somebody is telling me I'm going to buy 115 percent of what I need four years out. How does that even work?

Yet, I understand the need to show a signal to the market which the ISO I believe can easily do. The operating reserves -- the issue back to energy service providers free riding, last year on the peak hour, my portfolio was 98.3 percent accurate in terms of what I scheduled for what I used.

The ISO procured the operating reserves as they always do for me at 9 percent. Magically, that came out at exactly 7 percent operating reserves on that peak hour of the day of the year for my portfolio. It worked then, and it is going to continue to work, but we are getting distracted. People are pointing fingers too much, we are looking at things -- you know, if I pay $4.50 a KW a month or $8.00 a KW month to a generator for a resource adequacy product to meet my 15 to 17 percent, is that really a price signal that anybody in the investment community is going to look at? No, that is a $1.50 MWh on a $70 MWh price. It is not enough.

If I need to do a fair contract with generators to make sure that they stay here in this situation that we are in right now, we are ready to do that. We just don't want to be leveraged into a position where I have locational market power being used against me by a generator or on the resource adequacy side, (indiscernible) buying power by another competitive LSE that hammers me in a geography I can do nothing with.

As far as the business model because I

don't want to spend more of your time here, the business model as far as energy service provider, our business model, is not the enemy of a large LSE. We do something radically different from what they do.

In 1997, I gave a presentation to a large chip manufacturer SG Micro Electronics in Rancho Bernardo. We talked about triggers, we talked about indexing products, we talked about base load products, things like that. At that time, that customer had no comprehension of what I was talking about.

Two weeks ago I got a call from a customer that said I want 25 percent of my load indexed. I want 50 percent of it bought for the next three quarters and the remainder we will do day ahead. There was isn't any riding on the ISO or anything like that. The sophistication of the customer has exceeded our expectations even though it has been a long run, and we are seven years into this.

At the same time, the issue about three and four years and what does a direct access ESP type bring to the market place, if we had the core and non-core market so we did not have the regulatory uncertainty hanging over direct access customers, we would have three and four year contracts signed.

You would start seeing stability, but it is the chicken and the egg. It is the same old thing, but these customers -- when we say direct access, in 1996 direct access meant that we bring customers to the wholesale market. We give them access out there. Today in 2005, the meaning of the words direct access to us is that we have a direct relationship with customers that we actually can go into the load base and either bring communications or get information back instead of the aggregate bubble which does not give you that ability.

A specific point there, one large customer that is in the defense industry called me recently and said what are we going to do with resource adequacy? So, we had a discussion specific to potential charge types within the ISO. This is a customer talking about this. What we got to was if they plan on making any new facilities, where should they put them so they don't cause the problem or amplify charges.

Now all of the sudden instead of the old paradigm, you have customers, whether they are residential in the first example of 20/20 or CNI customers on direct access at a knowledge level you could never have attained in the previous days. The value of direct access from that perspective for a regulator, you have a direct conduit.

I live in a small town. In our town, you have emergency response operations. You don't' have a huge system to do that. People call other people and you have the old fashioned phone tree. You have that at your disposal any day you want, and that is not something we've had before. It is the same as the canary testing the coal mine. If you see me dying, you don't want to go in that cave.

PRESIDING MEMBER GEESMAN: Thanks very much, Bob. Fred.

MR. BUCKMAN: I'm Fred Buckman, the Chairman of Trans-Elect, and thank you very much for inviting me to be here.

Before my experience with Trans-Elect which goes back to about 1999, I spent about five years as the President and CEO of Pacific Corp, and before that, about six years as the President and CEO of Consumers Energy in Michigan.

While most of my comments will deal with the transmission issues today, feel free to ask questions of any way that you can use a perspective I have as someone who has been in the utility industry for a long time.

I was unable to hear the comments earlier today, but in listening to the comments of the panel today, I think there is a fair amount of sympathy amongst the people here in terms of how they see the questions that you are asking and how they would respond. I have a couple of fairly direct comments, and then I too would be happy to answer any questions that you have.

I notice in your questions on generation, there is a fair amount of attention paid to having access to new technology. I did not see that same level of emphasis in the transmission sector, but would point out in terms of the value of new technology, in terms of enhancing capacity in being able to go underground and being able to direct flows, there has been dramatic improvement made in the last decade. That if for no other reason than to gain access to new technology, substantial investment in transmission would be worthwhile in this state and in the West.

I would observe that the impact of what you are doing while you are focused on California, as someone who lives in Oregon, works in Washington D.C., and is involved with transmission systems around the country, what you are doing has impact far beyond the borders of California. I would say at least the entire western interconnect. So, getting answers to the questions do we have problems, and if so, what do we do about them is something that is very important, and I think it is worthwhile for people like me to be engaged and to work with you and try to sort this out.

You heard several people speak to the issue of 15 to 17 percent reserve margin. From my perspective, that is a question which cannot be answered in isolation. First of all, I have lived through oil embargoes, mine worker strikes, rail strikes, nuclear plant shut downs as the result of safety issues that were industry wide, and I can say that while today's attention on diversity is attention which is placed upon the high price of natural gas and perhaps to some extent the availability of natural gas, it will be a different problem. I don't know what it will be.

The question around reserve margin is one that has to be put into perspective of how much diversity do you really have. I would say that the more diversity you have, perhaps the lower you can go on reserve margins. The less diversity you have, the more comfort you will get in higher reserve margins.

The same can be said for transmission. To some extent, transmission and generation are interchangeable. In a transmission rich environment, I would be comfortable with a lower reserve margin than I would in a transmission poor environment.

I would characterize California as a transmission poor environment, and so my bias, both from a diversity perspective and from a transmission perspective, would be that more reserve rather than less reserve is something that will be suitable, not just to meet the needs of 2005. I heard the tail end of the last panel, I heard people talk about the adequacy of their resources for 2005, but as we know from a planning perspective, it is not really 2005 that we are worried about. It is how do things stack up over the next dozen years because the planning horizon for the kinds of infrastructure we are talking about are things like what we did for 2005 was done five or ten years ago.

It is what we are doing for the next decade and for the next generation that is really important. I am concerned about that. I'm concerned that this state is transmission poor and that it is difficult to build transmission in California.

Trans-Elect was an important part in building the upgrade to Path 15, something that I think from our perspective was very successful. We had great support here in California. We had great support nationwide. We were able to do it quickly. We were able to do it under budget, and it has performed to at least everybody's expectations and I think above many people's expectations.

It was a project that we joined in after it had already been on the books, in the works, trying to get done for somebody else by somebody else since I was a child. That is just unacceptable.

I have been searching for kind of what is it that I would like to see here. What I would like to see is an environment when transmission projects are proposed, they are accepted. There ought not to be in this environment a lot of discussion about whether a project is needed. They are all needed. In fact, if there are two competing projects for the same service, build them both, and then build a third just to be sure because in this state you can build transmission for a long time before you have to worry about whether or not you have too much.

Transmission investment represents a small part of the total energy infrastructure in this state. My guess would be about 10 percent.

PRESIDING MEMBER GEESMAN: Would you believe 5?

MR. BUCKMAN: I would believe 5. If you look at the amount of the bill that is devoted to paying for transmission, I would believe 1 percent. It doesn't make much difference whether you get it right regarding who exactly pays and how much exactly they pay for each mile of line that needs to be built.

Let's get it built. Let's create an

environment where we worry for awhile about getting built what needs to be built and trust that we can sort out the secondary issues as time goes on. That is what I think this state needs. It would be a terrific addition to the entire west if this state could find itself in that situation, and we would like to do anything we can to help.

PRESIDING MEMBER GEESMAN: I wish I knew where to start. I think that we may be in the course of proving ourselves constitutionally incapable, and I use that term constitutionally advisedly of getting a good handle on this.

Your comments reflect I think a general consensus among most of the stakeholders that have looked at this. There are a few outliers, but I think that most of those that have looked at this question in recent years agree we are transmission poor environment. Our analytic process fails to capture more than a small fraction of the benefits associated with additional transmission investment.

We are a rapidly growing state, currently about 35 million in population headed to 50 million over the course of the next 20 years. They are not making any more land. Projects are going to be easier to site today than it will be ten years from now, but we have despite several efforts in trying to figure out how to get on with it, not yet been successful.

MR. BUCKMAN: The 50 million people that you have in 20 years will each use more energy than the 35 million that you have today.

PRESIDING MEMBER GEESMAN: Yes. Our model for forecasting demand associates growth in electricity demand with growth in personal income. We intend to grow personal income.

The challenges that we face are primarily institutional and political, and we need the assistance. I think the engaged assistance. I think there has been a lack of engagement in some corners. We need the assistance of all of the range of California stakeholders to try and force government to better deal with this.

You were generous in the way you described the support you got on the Trans-Elect project. It wasn't universal support. There were some pockets of resistance.

MR. BUCKMAN: I think one of the things that an independent transmission company provides is the ability to deal with those pockets of resistance in a way which is far different from those people who have a lifetime of relationships that color the issues.

We were able to come in without maybe some of the advantage of those relationships, but also without the baggage that goes with them. I would like to think we were helpful in getting to solutions that made sense for all or most of the stakeholders. It was not my intent to be generous. It was my intent to say that compared to the reputation that California has for being a very difficult place for energy companies to do business, we did not find it nearly as difficult as we thought it would be.

It wasn't as though we didn't have problems, but they were problems that were surmountable, they were problems that were able to be dealt with, sort of in the ordinary course of business.

One thing I might mention in looking at the questions, there was a question about whether or not the IOU's have invested enough into transmission over the last some period of time. IOU's don't' make the investment in transmission, California makes the investment in transmission.

As I looked at that question, I thought to myself here is a kernel of what the problem is. There is a perhaps unintended search for the guilty.

You know, the IOU is but one part of the equation that gets transmission built. They happen to be the tip of the spear. It takes everybody to get it built, and you know, if your house was burning down, and you called the fire department, you wouldn't spend a lot of time on the phone trying to tell them what the most direct route was to get to your house. You would say my house is burning down, get here fast and put it out.

My sense is that there is an almost urgent need to spend time getting things perfectly in California and perhaps it is a constitutional necessity. While I am not ready to say the house is burning down, I smell smoke. If I were closer to it, I would probably conclude that it was burning down.

PRESIDING MEMBER GEESMAN: Let me ask you a couple of questions. One on the technology side, do you think that the IOU's are likely to be early adopters of the more advanced transmission technologies. I say that as an example, we do have a proposed independently owned line, a D.C.

line between the City of Pittsburgh and the City of San Francisco, a corridor that most people would tell you meets a fairly urgent need on the San Francisco Peninsula.

I should add in a parallel to your experience, not being generous right now, the PUC staff has recommended asserting jurisdiction over that project and opposing the financing arrangements at FERC, but that probably won't be anymore affective than the same staff was at trying to block your project. That is an independent sponsor adapting an advanced technology. In a regulated IOU's backyard, the opportunity has been there for years and years and years, but the utility sector didn't identify it, didn't pursue it.

MR. BUCKMAN: That is a good question. It is a little difficult to answer. From a utility perspective, there is not much reward for taking risk. Some of the new technology that we are talking about is technology which is not as well proven as that stuff which has been around for a generation.

Whether it is true or not, there is the perception that there is a bit more fairness and understanding at the federal regulatory level than there is at the state regulatory level. I am not pointing fingers at California because I would say that is true at virtually every one of the 50 states.

So, from that perspective, it is probably easier for an independent transmission company that is expecting FERC regulation to step out and propose something that has some technology risk to it than there is an IOU.

I can tell you that we've had a lot of discussions with IOU's, much of it in California, about doing joint projects in which we would apply new technology. It is not one of those things that I would be particularly worried about. I think that if there is a good application for undergrounding or for high voltage DC or for ceramic cables or for super conducting cables or things of that nature, I think the utilities might be what I would say is appropriately conservative, but I don't think they will be unreasonable in their willingness to take that on.

PRESIDING MEMBER GEESMAN: What would you think, though, of the response by the rate regulators at the state level and at the federal level?

MR. BUCKMAN: I think at the federal level, the response would be fairly unemotional. It would be show me the project, show me the benefits of doing it with technology "A" versus technology "B" versus technology "C", show me the risks, show me why you want to go the way you want to go. If we say okay to it, you can take it to the bank.

I think there is a feeling at most states that there is a little bit more backward look in regulation that it is fine that we say, okay, go ahead with it, but if it doesn't work out, it is on your shoulders, not ours.

The concerns about 20/20 hindsight in regulation are concerns which if I were the CEO of one of the utilities in California, I would be more concerned about state regulation than I would federal, but the same would be true if I were the CEO of a utility in Michigan or Oregon or Idaho or any place else.

PRESIDING MEMBER GEESMAN: Let me ask you to put your utility hat on and reflect on procurement of generation or procurement of contracts for generation. What level of transparency do you think is necessary or appropriate there from a utilities perspective?

MR. BUCKMAN: I have to separate my answer into two parts. There are some utilities that are also market participants in an unregulated way. There are some utilities that participate only through their regulated side of the business. I am not enthusiastic about utilities having an unregulated participation in the markets. There are some companies that are doing very well, although, I think that they might be abusing their position a bit. I know that FERC just spoke on the due power situation within the last couple of weeks, they also spoke on the southern situation.

Set those aside, and look at the ones that are purely regulated players, I would say that the kind of appropriate level of transparency is complete.

I think it is very difficult to have complete transparency if you are also a non-regulated participant.

PRESIDING MEMBER GEESMAN: You don't feel that based on your customer's interest, the rapacious generators might be able to take advantage of you if you had complete transparency in your procurement?

MR. BUCKMAN: You know, there are very small people in utilities, and the answer is that it is possible, but it is not one of the things I would lay awake at night worried about.

PRESIDING MEMBER GEESMAN: You truly are somebody from Oregon. I appreciate your being here, and I find your comments very helpful. Thank you. Thank you very much.

Jesus.

MR. ARREDONDO: Commissioners, good afternoon. My name is Jesus Arredondo, and I am here for the Western Power Trading Forum today.

We thank you for inviting us and allowing us a moment to share some of our thoughts as we reviewed the questions that were posted to this proceeding.

The biggest challenge is that we see the State of California having is attracting obviously new investment in generation and transmission as we here. In looking at those two issues, we think that you can group those into two areas. One is finishing what we have started, and the other is staying on point, staying on message.

The word that we get from perspective investors and financial community is that they see things changing, but they have not changed to the point where people are comfortable enough. In fact, we can look at outgoing FERC Chairman's exit interview if you will from last week that I think Greg referred to where he assigned a D+ to California.

PRESIDING MEMBER GEESMAN: Actually, if you had been here, you would have known that I referred to it and embraced it.

MR. ARREDONDO: Okay. I suppose we can embrace it even more if we measured it against blackouts and called those "F's" and a D+ is a good moving forward, but it is still not a passing grade if we were to look at it on a four point scale.

What can we do, and I think that is one of the issues that WPTF took with it. What we saw was you need a plan to come out from that D and move up in the grade scale and get a passing grade.

We have come up with a few points that I'll share, and in the interest of time, I know that going last is always a hard thing to do because people are starting to fall asleep and wondering about how they are getting home. So, I will try to go quick.

First under finishing what we started, No. 1, we need clear trading rules. Those have been touched on, but I want to touch on it just a little bit more. The ISO and the PUC with the CEC's urging must specify the energy delivery points for the ISO's future market design and how prices will be calculated at the trade hubs. How congestion will be allocated and settled, and adopted capacity product that is acceptable to both the PUC and the ISO.

While we applaud the recent achievements of these agencies in terms of establishing this long term procurement order, time is running out, and we need to get there a little bit sooner than later.

No. 2, we encourage the PUC -- we will encourage and we have been encouraging the PUC to issue the resource adequacy order by August. It is right around the corner. I hope that they make it. Detailed implementation plan for enforcing resource adequacy will encourage we hope FERC to ease or eliminate altogether some of the market mitigation rules that are impeding investment in California right now.

No. 3, as Katie alluded to earlier, we are also calling for the elimination of the ISO must offer obligation. That has been a huge hurdle for investment. It has been a terrible thing for IPP's, and we would like to see that go away.

In our second phase of looking at this strategy, we called it staying on message, and that we would call for the reinforcement of competitive solicitations. The CEC and the PUC have taken steps to encourage that, and we would like to again encourage you to continue on your efforts to do that.

Last, the state must hold open all options to establish a core/non-core market. That also is a huge hurdle for the investment community, for the utilities to get the rest of this market together from the PUC, from the CEC, from the ISO, from all perspectives to make sure we get this investment back into California. All of these need to be done so that California can have a passing grade I will call it. More importantly so that we can prevent the next crisis.

We lived through an ugly period and hopefully we are getting closer to a better time in California, and putting this behind us the sooner the better so that we can -- I don't know what we would do if we didn't all of these things, all of these hearings, but I look forward to that day. Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Jesus. I wonder if you could elaborate a bit more on your thoughts on an appropriate capacity product.

MR. ARREDONDO: You know, I will let some of our papers speak for themselves. We have quite a bit of information that we can offer to you, and I will request that the WPTF submit that in writing to you.

PRESIDING MEMBER GEESMAN: I would appreciate that. I think that is the only question I had.

Any comments or questions from the audience for this panel?

(No response.)

Anything else that we need to discuss today?

COMMISSIONER BOYD: I might say one thing, excuse the interruption, but I just want to let Mr. Buckman know that I too found his comments very refreshing. I very rarely try to compete with Commissioner Geesman when it comes to transmission issues. He has a passion and a knowledge far beyond mine, but as one who was part of a small group of people in early 2000 who was trying to get Path 15 fixed, I have a lot of painful memories and what have you, and that brought a lot of them back.

I just wanted to indicate that was refreshing, and as Commissioner Geesman said, he is obviously from Oregon. In any event, I look forward to more.

MR. BUCKMAN: Actually, I am from Michigan, I live in Oregon.

COMMISSIONER BOYD: Lucky you.

PRESIDING MEMBER GEESMAN: Let me say just from a historical context standpoint, my staff advisor, Ms. Jones, was involved in attempting to get the Path 15 project off the ground and then called the California Oregon Transmission line in the 1980's when it was perceived by our sister agency to be a white elephant and one which would never be built without the involvement of the investor owned utilities, so they were denied participation in it. So, we have a long history with some of these fiascos and hopefully we are working our way through that.

I want to thank everybody for hanging in there with us today. We will hopefully see you at another workshop soon. Thank you.

(Whereupon, the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, SEAN WILLARD, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 22nd day of July, 2005.

Sean Willard